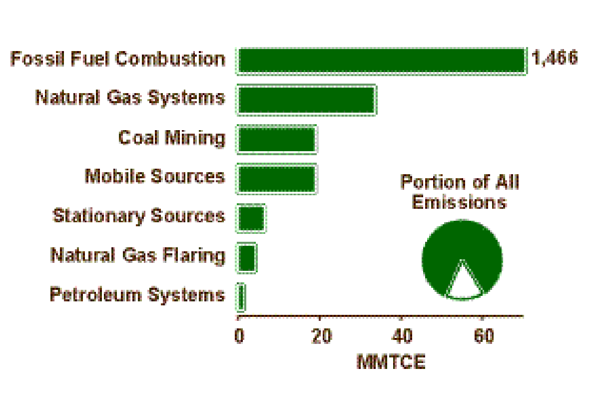
2. Energy

Energy-related activities were the primary source of U.S. anthropogenic greenhouse gas emissions, accounting for 85 percent of total emissions annually on a carbon equivalent basis in 1997. This included 99, 32, and 20 percent of the nation's carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions, respectively. Energy-related CO_2 emissions alone constituted 81 percent of national emissions from all sources on a carbon equivalent basis, while the non-CO_2 emissions from energy represented a much smaller portion of total national emissions (4 percent collectively).

Emissions from fossil fuel combustion comprise the vast majority of energy-related emissions, with CO_2 being the primary gas emitted (see Figure 2-1). Due to the relative importance of fossil fuel combustion-related CO_2 emissions, they are considered separately from other emissions. Fossil fuel combustion also emits CH_4 and N_2O, as well as criteria pollutants such as nitrogen oxides (NO_x), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs). Fossil fuel combustion—from stationary and mobile sources—was the second largest source N_2O emissions in the United States, and overall energy-related activities are the largest sources of criteria pollutant emissions.

Figure 2-1

1997 Energy Chapter GHG Sources



Energy-related activities other than fuel combustion, such as the production, transmission, storage, and distribution of fossil fuels, also emit greenhouse gases. These emissions consist primarily of CH_4 from natural gas systems, petroleum systems, and coal mining. Smaller quantities of CO_2, CO, NMVOCs, and NO_x are also emitted.

The combustion of biomass and biomass-based fuels also emits greenhouse gases. Carbon dioxide emissions from these activities, however, are not included in national emissions totals in the Energy chapter because biomass fuels are of biogenic origin. It is assumed that the carbon released when biomass is consumed is recycled as U.S. forests and crops regenerate, causing no net addition of CO_2 to be added to the atmosphere. The net impacts of land-use and forestry activities on the carbon cycle are accounted for in the Land-use change and Forestry chapter.

Overall, emissions from energy-related activities have increased from 1990 to 1997 due, in part, to the strong performance of the U.S. economy. Over this period, the U.S. Gross Domestic Product (GDP) grew approximately 18 percent, or at an average annual rate of 2.5 percent. This robust economic activity increased the demand for fossil fuels, with an associated increase in greenhouse gas emissions. Table 2-1 summarizes emissions for the Energy chapter in units of million metric tons of carbon equivalents (MMTCE), while unweighted gas emissions in teragrams (Tg) are provided in Table 2-2. Overall, emissions due to energy-related activities were 1,549.2 MMTCE in 1997, an increase of 10 percent since 1990.

Table 2-1: Emissions from Energy (MMTCE)

Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997
CO_2	**1,329.4**	**1,315.2**	**1,334.9**	**1,364.1**	**1,387.5**	**1,402.2**	**1,452.0**	**1,470.1**
Fossil Fuel Combustion	1,327.2	1,312.6	1,332.4	1,360.6	1,383.9	1,397.8	1,447.7	1,466.0
Natural Gas Flaring	2.3	2.6	2.6	3.5	3.6	4.5	4.3	4.2
International Bunker Fuels*	27.1	27.8	29.0	29.9	27.4	25.4	25.4	26.6
Biomass-Ethanol*	1.6	1.2	1.5	1.7	1.8	2.0	1.4	1.8
Biomass-Wood*	55.6	56.2	59.0	58.8	59.7	59.7	62.4	57.2
Non-Energy Use Carbon Stored*	(68.9)	(68.5)	(70.3)	(73.2)	(78.1)	(79.1)	(80.7)	(83.6)
CH_4	**62.2**	**61.4**	**61.3**	**58.6**	**58.2**	**58.9**	**58.1**	**57.4**
Stationary Sources	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.2
Mobile Sources	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Coal Mining	24.0	22.8	22.0	19.2	19.4	20.3	18.9	18.8
Natural Gas Systems	32.9	33.3	33.9	34.1	33.5	33.2	33.7	33.5
Petroleum Systems	1.6	1.6	1.6	1.6	1.6	1.6	1.5	1.6
International Bunker Fuels*	+	+	+	+	+	+	+	+
N_2O	**17.4**	**18.0**	**19.0**	**19.9**	**20.7**	**20.9**	**21.6**	**21.7**
Stationary Sources	3.8	3.8	3.9	3.9	4.0	4.0	4.1	4.1
Mobile Sources	13.6	14.2	15.2	15.9	16.7	17.0	17.4	17.5
International Bunker Fuels*	0.2	0.2	0.2	0.3	0.2	0.2	0.2	0.2
Total	**1,409.0**	**1,394.6**	**1,415.2**	**1,442.6**	**1,466.3**	**1,482.1**	**1,531.6**	**1,549.2**

* These values are presented for informational purposes only and are not included or are already accounted for in totals.
Note: Totals may not sum due to independent rounding.

Table 2-2: Emissions from Energy (Tg)

Gas/Source	1990	1991	1992	1993	1994	1995	1996	1997
CO_2	**4,874.6**	**4,822.4**	**4,894.8**	**5,001.7**	**5,087.5**	**5,141.6**	**5,324.0**	**5,390.4**
Fossil Fuel Combustion	4,866.2	4,812.8	4,885.4	4,988.7	5,074.4	5,125.1	5,308.3	5,375.2
Natural Gas Flaring	8.4	9.6	9.4	13.0	13.1	16.4	15.7	15.2
Biomass-Ethanol*	5.7	4.5	5.5	6.1	6.7	7.2	5.1	6.7
Biomass-Wood*	203.8	205.9	216.5	215.4	219.0	219.1	228.8	209.8
International Bunker Fuels*	99.3	101.9	106.4	109.6	100.4	93.3	93.0	97.5
Non-Energy Use Carbon Stored*	(252.7)	(251.2)	(257.8)	(268.5)	(286.5)	(289.9)	(295.9)	(306.6)
CH_4	**10.9**	**10.7**	**10.7**	**10.2**	**10.2**	**10.3**	**10.1**	**10.0**
Stationary Sources	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Mobile Sources	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal Mining	4.2	4.0	3.8	3.4	3.4	3.6	3.3	3.3
Natural Gas Systems	5.7	5.8	5.9	5.9	5.8	5.8	5.9	5.8
Petroleum Systems	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
International Bunker Fuels*	+	+	+	+	+	+	+	+
N_2O	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**
Stationary Sources	+	+	+	+	+	+	+	+
Mobile Sources	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
International Bunker Fuels*	+	+	+	+	+	+	+	+

+ Does not exceed 0.05 Tg
* These values are presented for informational purposes only and are not included or are already accounted for in totals.
Note: Totals may not sum due to independent rounding.

Carbon Dioxide Emissions from Fossil Fuel Combustion

In 1997, the majority of energy consumed in the United States, 85 percent, was produced through the combustion of fossil fuels such as coal, natural gas, and petroleum (see Figure 2-2 and Figure 2-3). Of the remaining, 7 percent was supplied by nuclear electric power and 8 percent by renewable energy technologies (EIA 1998a).

As fossil fuels are combusted, the carbon stored in the fuels is emitted as CO_2 and smaller amounts of other gases, including methane (CH_4), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs). These other gases are emitted as a by-product of incomplete fuel combustion. The amount of carbon in fuels varies significantly by fuel type. For example, coal contains the highest amount of carbon per unit of useful energy. Petroleum has roughly 75 percent of the carbon per unit of energy as coal, and natural gas has only about 55 percent.[1] Petroleum supplied the largest share of U.S. energy demands, accounting for an average of 39 percent of total energy consumption over the period of 1990 through 1997. Natural gas and coal followed in order of importance, accounting for an average of 24 and 22 percent of total consumption, respectively. Most petroleum was consumed in the transportation sector, while the vast majority of coal was used by electric utilities, with natural gas consumed largely in the industrial and residential sectors (see Figure 2-4)(EIA 1998a).

Emissions of CO_2 from fossil fuel combustion increased at an average annual rate of 1.4 percent from 1990 to 1997. The major factor behind this trend was a robust domestic economy, combined with relatively low energy prices. For example, petroleum prices have changed little in real terms since the 1970s, with coal prices actually having declined by more than 60 percent in real terms compared to the 1975 price (EIA 1998a) (see Figure 2-5). After 1990, when CO_2 emissions from fossil fuel combustion were 1,327.2 MMTCE (4,866.2 Tg), there was a slight decline of emissions in 1991 due to a national economic downturn, followed by an increase to 1,466.0 MMTCE (5,375.2 Tg) in 1997 (see Figure 2-5: Fossil Fuel Production Prices and Table 2-3 and Table 2-4). Overall, CO_2 emissions from fossil fuel combustion increased by 10.5 percent over the eight year period and rose by 1.3 percent in the final year.

Figure 2-2

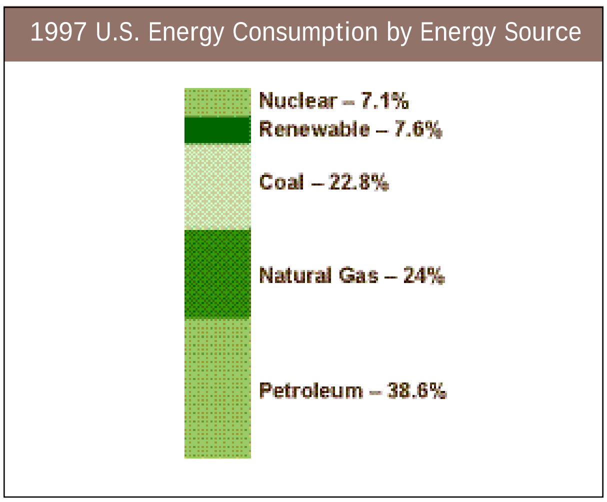


Figure 2-3

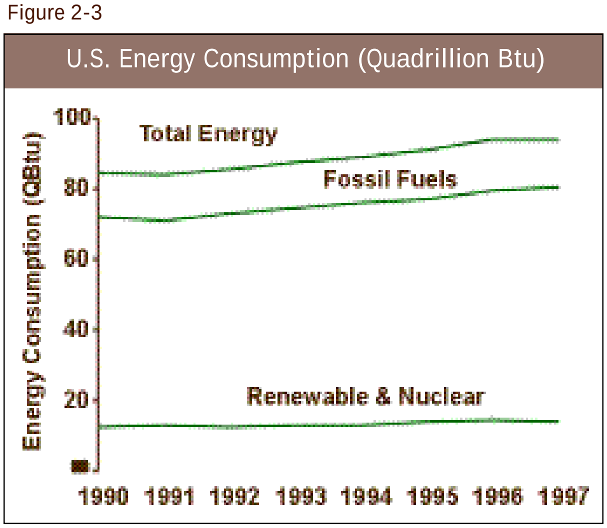
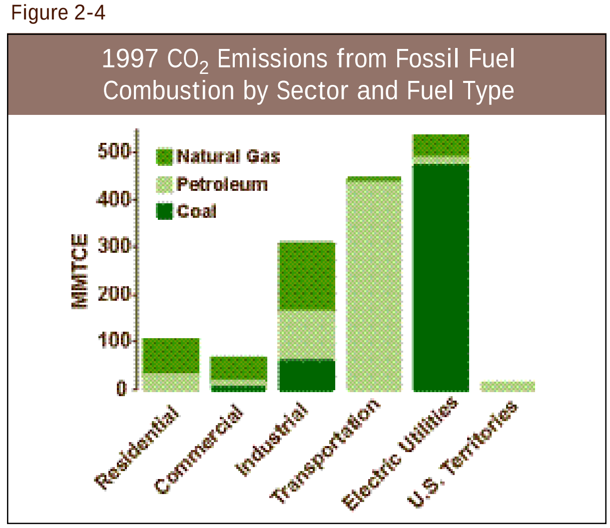


Figure 2-4



[1] Based on national aggregate carbon content of all coal, natural gas, and petroleum fuels combusted in the United States.

Figure 2-5

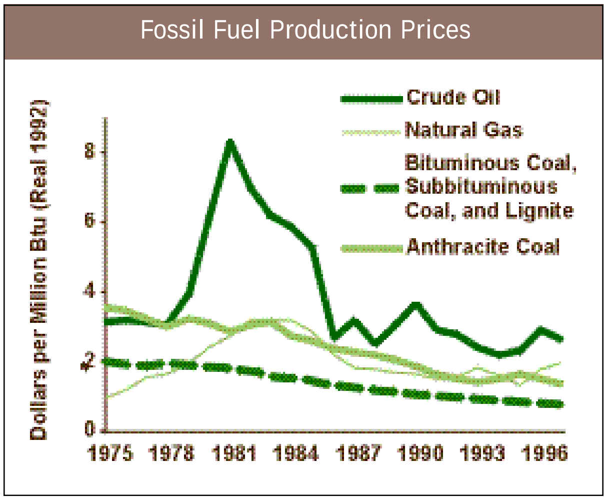


Table 2-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and Sector (MMTCE)

Fuel/Sector	1990	1991	1992	1993	1994	1995	1996	1997
Coal	**481.6**	**475.9**	**478.3**	**494.7**	**496.7**	**498.8**	**521.1**	**533.3**
Residential	1.6	1.4	1.5	1.5	1.4	1.4	1.4	1.4
Commercial	2.4	2.2	2.2	2.2	2.1	2.1	2.1	2.1
Industrial	68.5	64.8	62.6	62.2	62.7	62.1	59.9	58.5
Transportation	+	+	+	+	+	+	+	+
Electric Utilities	409.0	407.2	411.8	428.7	430.2	433.0	457.5	470.9
U.S. Territories	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3
Natural Gas	**273.5**	**278.4**	**286.5**	**297.0**	**301.9**	**314.5**	**319.3**	**319.4**
Residential	65.1	67.5	69.4	73.4	71.8	71.7	77.5	74.1
Commercial	38.8	40.4	41.5	43.1	42.9	44.8	46.7	48.6
Industrial	118.6	120.5	126.1	131.7	133.1	140.4	144.3	142.5
Transportation	9.8	8.9	8.8	9.3	10.2	10.4	10.6	10.5
Electric Utilities	41.2	41.1	40.7	39.5	44.0	47.2	40.3	43.8
U.S. Territories	-	-	-	-	-	-	-	-
Petroleum	**572.0**	**558.3**	**567.5**	**568.8**	**585.2**	**584.4**	**607.2**	**613.3**
Residential	23.9	24.4	24.8	26.2	25.3	25.7	27.2	27.7
Commercial	18.0	17.1	16.1	14.9	14.9	15.0	14.6	14.4
Industrial	100.0	94.3	104.3	98.0	102.0	98.2	103.9	106.0
Transportation	394.5	387.0	392.9	396.9	411.2	419.7	434.1	435.3
Electric Utilities	26.6	25.1	19.9	22.5	20.6	14.0	15.4	17.6
U.S. Territories	8.9	10.4	9.5	10.3	11.1	11.8	12.0	12.4
Geothermal*	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**
Total	**1,327.2**	**1,312.6**	**1,332.4**	**1,360.6**	**1,383.9**	**1,397.8**	**1,447.7**	**1,466.0**

- Not applicable
+ Does not exceed 0.05 MMTCE
* Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes.
Note: Totals may not sum due to independent rounding.

Table 2-4: CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and Sector (Tg)

Fuel/Sector	1990	1991	1992	1993	1994	1995	1996	1997
Coal	**1,765.9**	**1,744.8**	**1,753.8**	**1,814.0**	**1,821.3**	**1,828.9**	**1,910.9**	**1,955.3**
Residential	5.8	5.3	5.4	5.3	5.2	5.1	5.2	5.2
Commercial	8.7	8.0	8.1	8.1	7.9	7.6	7.8	7.8
Industrial	251.0	237.6	229.5	228.0	229.9	227.7	219.5	214.6
Transportation	+	+	+	+	+	+	+	+
Electric Utilities	1,499.7	1,493.2	1,510.0	1,571.7	1,577.4	1,587.5	1,677.4	1,726.7
U.S. Territories	0.6	0.7	0.8	0.9	0.9	0.9	1.0	1.0
Natural Gas	**1,002.9**	**1,020.8**	**1,050.5**	**1,088.8**	**1,107.1**	**1,153.3**	**1,170.8**	**1,171.1**
Residential	238.5	247.3	254.5	269.1	263.3	263.0	284.2	271.6
Commercial	142.4	148.2	152.3	158.2	157.4	164.3	171.2	178.1
Industrial	434.9	441.8	462.3	482.8	488.0	514.9	529.0	522.3
Transportation	36.0	32.8	32.1	33.9	37.2	38.1	38.7	38.6
Electric Utilities	151.1	150.6	149.3	144.9	161.2	173.0	147.7	160.5
U.S. Territories	-	-	-	-	-	-	-	-
Petroleum	**2,097.2**	**2,047.0**	**2,080.9**	**2,085.6**	**2,145.8**	**2,142.8**	**2,226.4**	**2,248.6**
Residential	87.7	89.4	90.9	96.1	92.8	94.4	99.7	101.5
Commercial	66.1	62.6	59.1	54.7	54.7	54.9	53.6	52.7
Industrial	366.6	345.7	382.3	359.5	374.2	360.1	381.1	388.5
Transportation	1,446.4	1,419.2	1,440.7	1,455.2	1,507.9	1,538.9	1,591.8	1,595.9
Electric Utilities	97.6	91.9	73.1	82.5	75.6	51.3	56.5	64.6
U.S. Territories	32.7	38.2	34.8	37.7	40.6	43.2	43.9	45.3
Geothermal*	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.1**	**0.1**	**0.1**
Total	**4,866.2**	**4,812.8**	**4,885.4**	**4,988.7**	**5,074.4**	**5,125.1**	**5,308.3**	**5,375.2**

\- Not applicable
\+ Does not exceed 0.05 Tg
* Although not technically a fossil fuel, geothermal energy-related CO_2 emissions are included for reporting purposes.
Note: Totals may not sum due to independent rounding.

Since 1990, consumption of all fossil fuels increased, with about 37 percent of the change in CO_2 emissions from fossil fuel combustion coming from coal, 33 percent from natural gas, and 30 percent from petroleum. From 1996 to 1997, absolute emissions from coal grew the most (an increase of 12.1 MMTCE or 2.3 percent), while emissions from natural gas changed the least (an increase of 0.1 MMTCE or less than 0.1 percent). During the same time period, emissions from electric utility petroleum and natural gas combustion increased the most on a percentage basis by 14.4 and 8.7 percent, respectively. See Box 2-1 for additional discussion on overall emission trends.

In 1997, combustion of fossil fuels by electric utilities increased, in part, to offset the temporary shutdown of several nuclear power plants and two plant closings. As a result, in 1997 the U.S. coal industry produced the largest amount of coal ever and electric utilities consumed record quantities. Electric utilities increased consumption by 2.8 percent from 1996 levels. The aggregate consumption of coal in sectors other than electric utilities actually declined by 2.6 percent (EIA 1998f) during this period. The net increase in coal consumption by all sectors was responsible for 66 percent of the total increase in CO_2 emissions from fossil fuel combustion.

Continued low prices encouraged the consumption of petroleum products in 1997, which increased by 1.3 percent from the previous year. This rise in petroleum use accounted for 33 percent of the increase in CO_2 emissions from fossil fuel combustion.

From 1996 to 1997, emissions from natural gas held steady. Consumption decreases in the industrial and residential sectors offset increases in the commercial and electric utility sectors.

Fossil fuels also have applications other than combustion for energy. For example, some petroleum products can be used for manufacturing plastics, asphalt, or lubricants. A portion of the carbon consumed for these non-energy uses is sequestered for long periods of time. In addition, as required by the IPCC (IPCC/UNEP/OECD/IEA 1997) CO_2 emissions from the consumption of fossil fuels for aviation and marine international transport activities (i.e., bunker fuels) are reported separately, and not included in national emission totals. Both estimates for non-energy use carbon stored and international bunker fuel emissions for the United States are provided in Table 2-5 and Table 2-6.

End-Use Sector Contributions

When analyzing CO_2 emissions from fossil fuel combustion, four end-use sectors can be identified: industrial, transportation, residential, and commercial. Electric utilities also emit CO_2; however, these emissions occur as they combust fossil fuels to provide electricity to one of the four end-use sectors. For the discussion below, electric utility emissions have been distributed to each end-use sector based upon their share of national electricity consumption. Emissions from electric utilities are addressed separately after the end-use sectors have been discussed. Emissions from U.S. territories are also calculated separately due to a lack of end-use-specific consumption data. Table 2-7 and Figure 2-6 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Industrial End-Use Sector

The industrial end-use sector accounted for approximately one-third of CO_2 emissions from fossil fuel combustion. On average, nearly 64 percent of these emissions resulted from the direct consumption of fossil fuels in order to meet industrial demand for steam and process heat. The remaining 36 percent resulted from

Figure 2-6

1997 End-Use Sector Emissions of CO_2 from Fossil Fuel Combustion

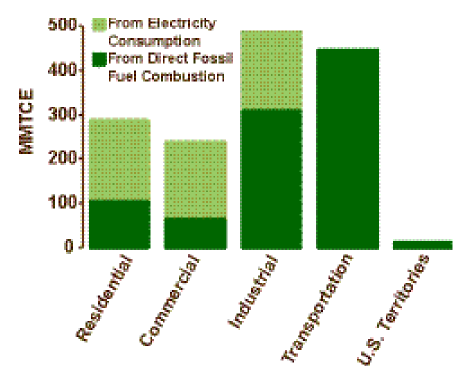


Table 2-5: Non-Energy Use Carbon Stored and CO_2 Emissions from International Bunker Fuel Combustion (MMTCE)

Category/Sector	1990	1991	1992	1993	1994	1995	1996	1997
Non-Energy Use Carbon Stored	**68.9**	**68.5**	**70.3**	**73.2**	**78.1**	**79.1**	**80.7**	**83.6**
Industrial	67.0	66.7	68.6	71.4	76.3	77.2	78.8	81.7
Transportation	1.8	1.6	1.6	1.7	1.7	1.7	1.6	1.7
Territories	0.2	0.2	0.1	0.2	0.1	0.1	0.2	0.2
International Bunker Fuels*	**27.1**	**27.8**	**29.0**	**29.9**	**27.4**	**25.4**	**25.4**	**26.6**
Aviation*	10.5	10.5	11.0	11.2	11.6	12.4	12.8	13.9
Marine*	16.6	17.3	18.0	18.7	15.8	13.0	12.6	12.7

* Excludes military international bunkers fuels. See International Bunker Fuels for additional detail.
Note: Totals may not sum due to independent rounding.

Table 2-6: Non-Energy Use Carbon Stored and CO_2 Emissions from International Bunker Fuel Combustion (Tg)

Category/Sector	1990	1991	1992	1993	1994	1995	1996	1997
Non-Energy Use Carbon Stored	**252.7**	**251.2**	**257.8**	**268.5**	**286.5**	**289.9**	**295.9**	**306.6**
Industrial	245.6	244.5	251.4	261.8	279.6	283.2	289.0	299.4
Transportation	6.5	5.8	6.0	6.1	6.3	6.2	6.0	6.4
Territories	0.6	0.9	0.4	0.6	0.5	0.5	0.8	0.9
International Bunker Fuels*	**99.3**	**101.9**	**106.4**	**109.6**	**100.4**	**93.3**	**93.0**	**97.5**
Aviation*	38.4	38.4	40.4	41.1	42.5	45.5	47.0	51.0
Marine*	60.8	63.5	66.0	68.5	57.9	47.8	46.0	46.6

* Excludes military international bunkers fuels. See International Bunker Fuels for additional detail.
Note: Totals may not sum due to independent rounding.

Table 2-7: CO_2 Emissions from Fossil Fuel Combustion by End-Use Sector (MMTCE)*

End-Use Sector	1990	1991	1992	1993	1994	1995	1996	1997
Residential	253.0	257.1	255.7	271.6	268.6	269.8	285.4	286.1
Commercial	206.8	206.4	205.3	212.1	214.1	218.4	225.9	237.1
Industrial	453.3	441.8	459.3	459.5	467.8	466.8	478.8	483.7
Transportation	405.0	396.7	402.4	406.8	422.1	430.7	445.3	446.5
U.S. Territories	9.1	10.6	9.7	10.5	11.3	12.0	12.2	12.6
Total	**1,327.2**	**1,312.6**	**1,332.4**	**1,360.6**	**1,383.9**	**1,397.8**	**1,447.7**	**1,466.0**

* Emissions from fossil fuel combustion by electric utilities are allocated based on electricity consumption by each end-use sector.
Note: Totals may not sum due to independent rounding.

the consumption of electricity for uses such as motors, electric furnaces, ovens, and lighting. Although industry accounted for the largest share of end-use sector emissions, from 1990 to 1997 its emissions grew the least in percentage terms (7 percent). During the same period, coal consumption by industry declined by 15 percent, while natural gas and petroleum consumption increased by 20 and 6 percent, respectively.

The industrial end-use sector was also the largest user of fossil fuels for non-energy applications. Fossil fuels can be used for producing products such as fertilizers, plastics, asphalt, or lubricants, that sequester or store carbon for long periods of time. Asphalt used in road construction, for example, stores carbon essentially indefinitely. Similarly, fossil fuels used in the manufacture of materials like plastics can also store carbon, if the material is not burned. Carbon stored by industrial non-energy uses of fossil fuels rose 22 percent between 1990 and 1997, to 81.7 MMTCE (306.6 Tg CO_2).

Transportation End-Use Sector

Transportation was second to the industrial end-use sector in terms of U.S. CO_2 emissions from fossil fuel combustion emissions, accounting for slightly over 30 percent—excluding international bunker fuels. Almost all of the energy consumed in this end-use sector came from petroleum-based products, with nearly two-thirds due to gasoline consumption in automobiles and other highway vehicles. Other uses, including diesel fuel for the trucking industry and jet fuel for aircraft, accounted for the remainder.

Following the overall trend in U.S. energy consumption, fossil fuel combustion for transportation grew steadily after declining in 1991, resulting in a 10 percent increase in CO_2 emissions to 446.5 MMTCE (1,637.1 Tg) in 1997. This increase was primarily the result of greater motor gasoline, distillate fuel oil (e.g., diesel), and jet fuel consumption. It was slightly offset by decreases in the consumption of aviation gasoline, LPG, lubricants, and residual fuel. Overall, motor vehicle fuel efficiency stabilized in the 1990s after increasing steadily since 1977 (EIA 1998a). This trend was due, in part, to a decline in gasoline prices and new motor vehicle sales being increasingly dominated by less fuel-efficient light-duty trucks and sport-utility vehicles (see Figure 2-7 and Figure 2-8). Moreover, declining petroleum prices during these years—with the exception of 1996—combined with a stronger economy, were largely responsible for an overall increase in vehicle miles traveled by on-road vehicles ().

Table 2-8 below provides a detailed breakdown of CO_2 emissions by fuel category and vehicle type for the transportation end-use sector. On average 60 percent of the emissions from this end-use sector were the result

Figure 2-7

Motor Gasoline Retail Prices (Real)

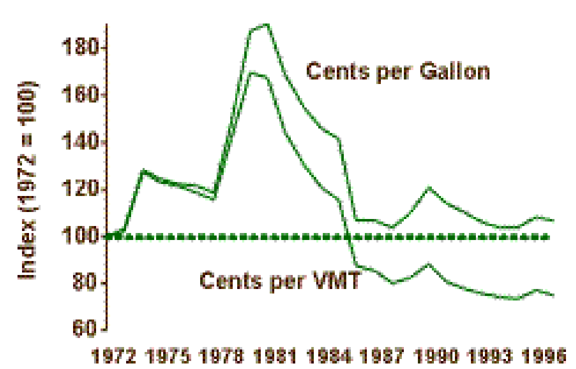
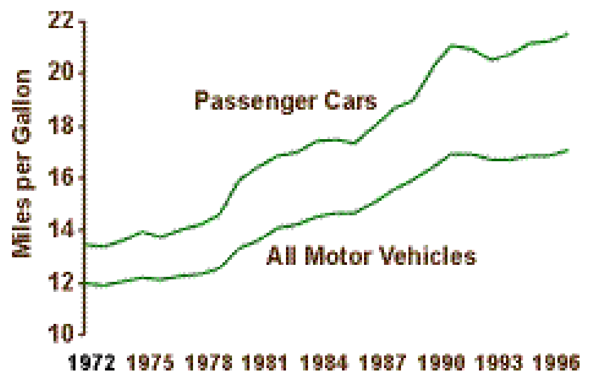


Figure 2-8

Motor Vehicle Fuel Efficiency



of the combustion of motor gasoline in passenger cars and light-duty trucks. Diesel highway vehicles and jet aircraft were also significant contributors, each accounting for, on average, 13 percent of CO_2 emissions from the transportation end-use sector. It should be noted that the U.S. Department of Transportation's Federal Highway Administration altered its definition of light-duty trucks in 1995 to include sport-utility vehicles and minivans; previously these vehicles were included under the passenger cars category. As a consequence of this reclassification, a discontinuity exists in the time series in Table 2-8 for both passenger cars and light-duty trucks.[2] In future editions of this report a consistent classification scheme across the entire time series will be applied by incorporating adjustments in the allocation of fuel consumption for the period 1990 to 1995 to eliminate this discontinuity.

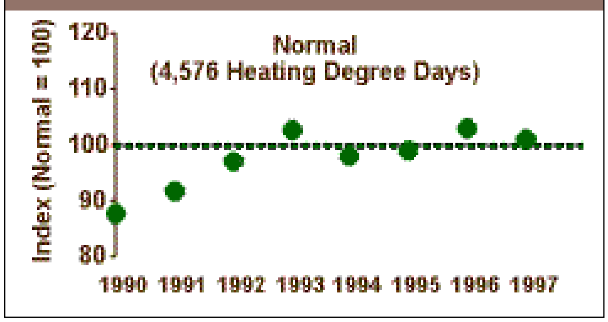
The annual increase in CO_2 emissions from motor gasoline in 1997 is based on fuel sales data from the U.S. Energy Information Administration; it is expected to be revised upward with the publication of future energy statistics. Carbon stored in lubricants used for transportation activities were 1.7 MMTCE (6.4 Tg) in 1997.

Residential and Commercial End-Use Sectors

From 1990 to 1997, the residential and commercial end-use sectors, on average, accounted for 19 and 16 percent, respectively, of CO_2 emissions from fossil fuel combustion. Both the residential and commercial end-use sectors were heavily reliant on electricity for meeting energy needs, with about two-thirds of their emissions attributable to electricity consumption for lighting, heating, cooling, and operating appliances. The remaining emissions were largely due to the direct consumption of natural gas and petroleum products, primarily for heating and cooking needs. Unlike in other major end-use sectors, emissions from residences did not decline in 1991, but instead decreased in 1992 and 1994, then grew steadily through 1997 (see Figure 2-9). This difference in overall trends compared to other end-use sectors is because energy consumption in residences is affected proportionately more by the weather than by prevailing economic conditions. The commercial end-use sector, however, is primarily dependent on electricity for lighting and is affected more by the number of commercial consumers. Coal consumption was a small component of energy use in both the residential and commercial sectors.

Figure 2-9

Heating Degree Days[3]



Electric Utilities

The United States relied on electricity to meet a significant portion of its energy requirements. Electricity was consumed primarily in the residential, commercial, and industrial end-use sectors for uses such as lighting, heating, electric motors, and air conditioning (see Figure 2-10). To generate this electricity, utilities consumed 28 percent of national fossil fuels on an energy content basis and were collectively the largest producers of CO_2 emissions from fossil fuel combustion, accounting for 36 percent in 1997. Electric utilities were responsible for a larger share of these CO_2 emissions

[2] See Box 1-2 in the Introduction chapter for a discussion on emissions of all greenhouse gases from transportation related activities.

[3] Degree days are relative measurements of outdoor air temperature. Heating degree days are deviations of the mean daily temperature below 65° F. Excludes Alaska and Hawaii. Normals are based on data from 1961 through 1990.

Table 2-8: CO_2 Emissions from Fossil Fuel Combustion in Transportation End-Use Sector (MMTCE)

Fuel/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997
Motor Gasoline	**260.9**	**259.5**	**263.4**	**269.3**	**273.7**	**279.9**	**285.2**	**288.3**
Passenger Cars*	167.3	165.9	170.0	171.5	170.5	173.5	158.7	160.4
Light-Duty Trucks*	74.9	74.7	74.6	77.8	84.2	85.9	106.1	107.2
Other Trucks	11.3	11.2	11.2	11.7	10.4	10.9	11.1	11.3
Motorcycles	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5
Buses	0.6	0.6	0.6	0.7	0.9	0.8	0.6	0.6
Construction Equipment	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7
Agricultural Machinery	1.2	1.2	1.2	2.0	2.1	2.2	2.1	2.2
Boats (Recreational)	4.6	4.8	4.7	4.6	4.5	5.3	5.4	5.5
Distillate Fuel Oil (Diesel)	**75.7**	**72.6**	**75.3**	**77.3**	**82.5**	**83.8**	**89.8**	**91.6**
Passenger Cars*	2.0	1.9	2.0	2.1	2.0	2.1	2.1	2.1
Light-Duty Trucks*	2.5	2.4	2.5	2.6	2.8	3.0	3.6	3.7
Other Trucks	45.8	43.7	45.2	48.0	52.0	53.0	57.0	58.1
Buses	2.2	2.2	2.3	2.3	2.4	2.7	2.4	2.4
Construction Equipment	2.9	2.9	2.9	2.9	2.9	2.8	3.0	3.0
Agricultural Machinery	6.5	6.3	6.4	6.4	6.4	6.2	6.6	6.7
Boats (Freight)	5.0	4.8	5.1	4.7	4.6	4.4	5.1	5.2
Locomotives	7.3	6.8	7.3	6.6	7.9	8.0	8.7	8.8
Marine Bunkers	1.4	1.6	1.6	1.6	1.5	1.7	1.4	1.6
Jet Fuel	**60.1**	**58.1**	**57.6**	**58.1**	**60.4**	**60.0**	**62.7**	**63.3**
General Aviation	1.7	1.5	1.3	1.3	1.2	1.4	1.5	1.5
Commercial Air Carriers	32.0	29.6	30.5	30.9	32.0	32.8	33.9	33.9
Military Vehicles	16.0	16.5	14.8	14.6	15.6	13.4	14.5	14.0
Aviation Bunkers	10.5	10.5	11.0	11.2	11.6	12.4	12.8	13.9
Aviation Gasoline	**0.8**	**0.8**	**0.8**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
General Aviation	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7
Residual Fuel Oil	**21.9**	**22.0**	**23.0**	**19.4**	**19.1**	**18.5**	**19.2**	**15.9**
Boats (Freight)	6.8	6.3	6.7	2.4	4.8	7.1	8.0	4.8
Marine Bunkers	15.2	15.7	16.4	17.1	14.3	11.4	11.2	11.1
Natural Gas	**9.8**	**8.9**	**8.8**	**9.3**	**10.2**	**10.4**	**10.6**	**10.5**
Passenger Cars*	+	+	+	+	+	+	+	+
Light-Duty Trucks*	+	+	+	+	+	+	+	+
Buses	+	+	+	+	+	+	+	+
Pipeline	9.8	8.9	8.8	9.2	10.1	10.4	10.5	10.5
LPG	**0.4**	**0.3**	**0.3**	**0.3**	**0.5**	**0.5**	**0.3**	**0.3**
Light-Duty Trucks*	0.1	0.1	0.1	0.1	0.2	0.3	0.1	0.1
Other Trucks	0.2	0.2	0.2	0.2	0.3	0.3	0.1	0.2
Buses	+	+	+	+	+	+	+	+
Electricity	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Buses	+	+	+	+	+	+	+	+
Locomotives	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Pipeline	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Lubricants	**1.8**	**1.6**	**1.6**	**1.6**	**1.7**	**1.7**	**1.6**	**1.7**
Total (including bunkers)	**432.1**	**424.5**	**431.4**	**436.7**	**449.4**	**456.2**	**470.7**	**473.1**

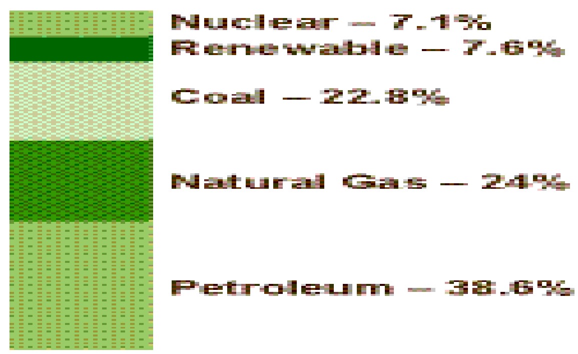
Note: Totals may not sum due to independent rounding. Estimates include emissions from the combustion of both aviation and marine international bunker fuels in civilian vehicles only. Military international bunker fuels are not estimated separately.

+ Does not exceed 0.05 MMTCE

*In 1996, the U.S. Federal Highway Administration modified the definition of light-duty trucks to include minivans and sport utility vehicles. Previously, these vehicles were included under the passenger cars category. Hence the sharp drop in emissions for passenger cars from 1995 to 1996 occurred. This gap, however, was offset by an equivalent rise in emissions from light-duty trucks.

Figure 2-10

Electric Utility Retail Sales by End-Use Sector



mainly because they rely on more carbon intensive coal for a majority of their primary energy. Some of the electricity consumed in the United States was generated using low or zero CO_2 emitting technologies such as hydroelectric or nuclear energy; however, in 1997 the combustion of coal was the source of 57 percent of the electricity consumed in the United States (EIA 1998b).

Electric utilities were the dominant consumer of coal in the United States, accounting for 87 percent in 1997. Consequently, changes in electricity demand have a significant impact on coal consumption and associated CO_2 emissions. In fact, electric utilities consumed record amounts of coal (922 million short tons) in 1997. Overall, emissions from coal burned at electric utilities increased by 15 percent from 1990 to 1997. This increase in coal-related emissions from electric utilities was alone responsible for 45 percent of the overall rise in CO_2 emissions from fossil fuel combustion.

In addition to the increase in consumption of coal by electric utilities, consumption of both natural gas and petroleum rose by 9 and 14 percent in 1997,respectively (EIA 1998e). Electric utility natural gas use increased significantly in 1994 and 1995, as prices and supply stabilized following a series of cold winters and a period of industry restructuring. However, in 1996 gas prices paid by electric utilities increased by a dramatic 33 percent (EIA 1997a), making gas-based electricity generation less economical. Consequently, natural gas consumption by electric utilities declined by 15 percent in 1996. The rebound in 1997 regained half of the previous year's decline. This increased gas consumption occurred mostly in California, where hydroelectric and nuclear generation each fell by 10 percent, and in New York, where nuclear generation fell by 16 percent. Over the 1990 to 1997 period, emissions from natural gas burned at electric utilities rose by 6 percent. Fuel oil was the most expensive fossil fuel delivered to electric utilities in 1997, 62 percent more costly than natural gas on an energy content basis. Consequently, petroleum constituted a small portion of electric utility fossil fuel consumption (4 percent in 1997) and occurred mostly in the eastern United States.

In 1997, consumption of all fossil fuels for producing electricity increased to accommodate the temporary shut-down of several nuclear power plants across the country and two plant closings. Total nuclear power plants electricity generation fell off by 7 percent accounting for 1.5 percent of total national generation (45.3 billion kilowatt hours) (EIA 1998b).

Box 2-1: Sectoral Carbon Intensity Trends Related to Fossil Fuel and Overall Energy Consumption

Fossil fuels are the predominant source of energy in the United States, and carbon dioxide (CO_2) is emitted as a product from their complete combustion. Useful energy, however, can be generated from many other sources that do not emit CO_2 in the energy conversion process.[4] In the United States, useful energy is also produced from renewable (i.e., hydropower, biofuels, geothermal, solar, and wind) and nuclear sources.

Energy-related CO_2 emissions can be reduced by not only reducing total energy consumption (e.g., through conservation measures) but also by lowering the carbon intensity of the energy sources employed (i.e., fuel switching from coal to natural gas). The amount of carbon emitted—in the form of CO_2—from the combustion of fossil fuels is dependent upon the carbon content of the fuel and the fraction of that carbon that is oxidized. Fossil fuels vary in their carbon content, ranging from 13.7 MMTCE/EJ for natural gas to 26.4 MMTCE/EJ for coal and petroleum coke.[5] In general, the carbon intensity of fossil fuels is the highest for coal products, followed by petroleum and then natural gas. Other sources of energy, however, may be directly or indirectly carbon neutral (i.e., 0 MMTCE/EJ). Energy generated from nuclear and many renewable sources do not result in direct emissions of CO_2. Biofuels such as wood and ethanol are also considered to be carbon neutral, as the CO_2 emitted during combustion is assumed to be offset by the carbon sequestered in the growth of new biomass.[6] The overall carbon intensity of the U.S. economy is then dependent upon the combination of fuels and other energy sources employed to meet demand.

Table 2-9 provides a time series of the carbon intensity for each sector of the U.S. economy. The time series incorporates only the energy consumed from the direct combustion of fossil fuels in each sector. For example, the carbon intensity for the residential sector does not include the energy from or emissions related to the consumption of electricity for lighting or wood for heat. Looking only at this direct consumption of fossil fuels, the residential sector exhibited the lowest carbon intensity, which was related to the large percentage of energy derived from natural gas for heating. The carbon intensity of the commercial sector was greater than the residential sector for the period from 1990 to 1996, but then declined to an equivalent level as commercial businesses shifted away from petroleum to natural gas. The industrial sector was more dependent on petroleum and coal than either the residential or commercial sectors, and thus had a higher carbon intensity over this period. The carbon intensity of the transportation sector was closely related to the carbon content of petroleum products (e.g., motor gasoline and jet fuel), which were the primary sources of energy. Lastly, the electric utility sector had the highest carbon intensity due to its heavy reliance on coal for generating electricity.

Table 2-9: Carbon Intensity from Direct Fossil Fuel Combustion by Sector (MMTCE/EJ)

Sector	1990	1991	1992	1993	1994	1995	1996	1997
Residential[a]	14.7	14.7	14.6	14.6	14.6	14.6	14.6	14.7
Commercial[a]	15.2	15.1	15.0	14.9	14.9	14.8	14.8	14.7
Industrial[a]	16.6	16.5	16.5	16.4	16.4	16.3	16.3	16.3
Transportation[a]	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Electric Utilities[b]	22.4	22.4	22.4	22.5	22.4	22.4	22.6	22.6
All Sectors[c]	**18.6**	**18.6**	**18.6**	**18.6**	**18.6**	**18.5**	**18.5**	**18.6**

[a] Does not include electricity or renewable energy consumption.
[b] Does not include electricity produced using nuclear or renewable energy.
[c] Does not include nuclear or renewable energy consumption.
Note: Excludes non-energy fuel use emissions and consumption. Exajoule (EJ) = 10^{18} joules = 0.9479 QBtu.

[4] CO_2 emissions, however, may be generated from upstream activities (e.g., manufacture of the technologies).

[5] One exajoule (EJ) is equal to 10^{18} joules or 0.9478 QBtu.

[6] This statement assumes that there is no net loss of biomass-based carbon due to biofuel consumption.

In contrast to Table 2-9, Table 2-10 presents carbon intensity values that incorporate energy consumed from all sources (i.e., fossil fuels, renewables, and nuclear). In addition, the emissions related to the generation of electricity have been attributed to both electric utilities and the sector in which that electricity was eventually consumed.[7] This table, therefore, provides a more complete picture of the actual carbon intensity of each sector per unit of energy consumed. Both the residential and commercial sectors obtain a large portion of their energy from electricity. The residential sector, however, also uses significant quantities of biofuels such as wood, thereby lowering its carbon intensity. The industrial sector uses biofuels in even greater quantities than the residential sector. The carbon intensity of electric utilities differs greatly from the scenario in Table 2-9 where only the energy consumed from the direct combustion of fossil fuels was included. This difference is due almost entirely to the inclusion of electricity generation from nuclear and hydropower sources, which do not emit carbon dioxide. Also in contrast with the previous scenario in Table 2-9, the transportation sector in Table 2-10 emerges as the most carbon intensive when all sources of energy are included, due to its almost complete reliance on petroleum products and relatively minor amount of biomass based fuels such as ethanol.

Table 2-10: Carbon Intensity from Energy Consumption by Sector (MMTCE/EJ)

Sector	1990	1991	1992	1993	1994	1995	1996	1997
Residential[a]	14.5	14.3	14.4	14.5	14.5	14.2	14.3	14.7
Commercial[a]	15.2	15.0	15.1	15.2	15.1	14.8	14.9	15.1
Industrial[a]	14.8	14.6	14.6	14.6	14.6	14.4	14.4	14.5
Transportation[a]	18.0	18.1	18.1	18.0	18.0	18.0	18.0	18.0
Electric Utilities[b]	15.3	15.0	15.2	15.3	15.2	14.8	15.0	15.3
All Sectors[c]	**15.8**	**15.6**	**15.7**	**15.7**	**15.7**	**15.5**	**15.5**	**15.7**

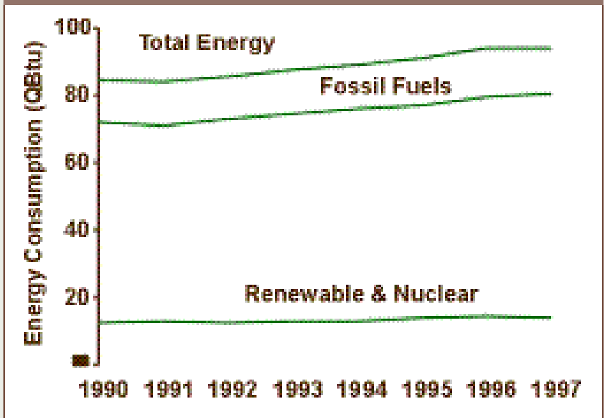
[a] Includes electricity (from fossil fuel, nuclear, and renewable sources) and direct renewable energy consumption.
[b] Includes electricity generation from nuclear and renewable sources.
[c] Includes nuclear and renewable energy consumption.
Note: Excludes non-energy fuel use emissions and consumption. Assumed that residential consumed all of the biofuel-based energy and 50 percent of the solar energy in the combined EIA residential/commercial sector category. Exajoule (EJ) = 10^{18} joules = 0.9479 QBtu.

By comparing the values in Table 2-9 and Table 2-10, there are a couple of observations that can be made. The usage of renewable and nuclear energy sources have resulted in a significantly lower carbon intensity of the U.S. economy, especially for the industrial and electric utility sectors. However, over the eight year period of 1990 through 1997, the carbon intensity of U.S. fossil fuel consumption has been fairly constant, and changes in the usage of renewable and nuclear energy technologies have not altered this trend.

Figure 2-11 and Table 2-11 present the detailed CO_2 emission trends underlying the carbon intensity differences and changes described in Table 2-9. In Figure 2-11 changes in both overall end-use-related emissions and electricity-related emissions for each year since 1990 are highlighted. In Table 2-11 values are normalized in the year 1990 to one-hundred (100), thereby highlighting changes over time.

Figure 2-11

Change in CO_2 Emissions from Fossil Fuel Combustion Since 1990 by End-Use Sector



[7] In other words, the emissions from the generation of electricity are intentionally double counted by attributing them both to utilities and the sector in which electricity consumption occurred.

Table 2-11: CO_2 Emissions from Fossil Fuel Combustion (Index 1990 = 100)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997	% of '97
Residential	**100**	**103**	**106**	**112**	**109**	**109**	**117**	**114**	**7.0%**
Coal	100	91	92	92	90	87	89	89	0.1%
Natural Gas	100	104	107	113	110	110	119	114	5.1%
Petroleum	100	102	104	110	106	108	114	116	1.9%
Commercial	**100**	**101**	**101**	**102**	**101**	**104**	**107**	**110**	**4.4%**
Coal	100	91	93	92	90	87	89	89	0.1%
Natural Gas	100	104	107	111	110	115	120	125	3.3%
Petroleum	100	95	89	83	83	83	81	80	1.0%
Industrial	**100**	**97**	**102**	**102**	**104**	**105**	**107**	**107**	**20.9%**
Coal	100	95	91	91	92	91	87	85	4.0%
Natural Gas	100	102	106	111	112	118	122	120	9.7%
Petroleum	100	94	104	98	102	98	104	106	7.2%
Transportation	**100**	**98**	**99**	**100**	**104**	**106**	**110**	**110**	**30.4%**
Coal	-	-	-	-	-	-	-	-	-
Natural Gas	100	91	89	94	103	106	108	107	0.7%
Petroleum	100	98	100	101	104	106	110	110	29.7%
Electric Utility	**100**	**99**	**99**	**103**	**104**	**104**	**108**	**112**	**36.3%**
Coal	100	100	101	105	105	106	112	115	32.1%
Natural Gas	100	100	99	96	107	115	98	106	3.0%
Petroleum	100	94	75	84	77	53	58	66	1.2%
U.S. Territories	**100**	**117**	**107**	**116**	**125**	**132**	**135**	**139**	**0.9%**
Coal	100	110	126	137	146	148	152	152	0.0%
Natural Gas	-	-	-	-	-	-	-	-	-
Petroleum	100	117	106	115	124	132	134	139	0.8%
All Sectors	**100**	**99**	**100**	**103**	**104**	**105**	**109**	**110**	**100.0%**

- Not applicable

Note: Totals may not sum due to independent rounding.

Methodology

The methodology used by the United States for estimating CO_2 emissions from fossil fuel combustion is conceptually similar to the approach recommended by the IPCC for countries that intend to develop detailed, sectoral-based emission estimates (IPCC/UNEP/OECD/IEA 1997). A detailed description of the U.S. methodology is presented in Annex A, and is characterized by the following steps:

1. *Determine fuel consumption by fuel type and sector*. By aggregating consumption data by sector (e.g., commercial, industrial, etc.), primary fuel type (e.g., coal, petroleum, gas), and secondary fuel category (e.g., motor gasoline, distillate fuel oil, etc.), estimates of total U.S. fossil fuel consumption for a particular year were made.[8] The United States does not include territories in its national energy statistics; therefore, fuel consumption data for territories was collected separately.

2. *Determine the total carbon content of fuels consumed*. Total carbon was estimated by multiplying the amount of fuel consumed by the amount of carbon in each fuel. This total carbon estimate defines the maximum amount of carbon that could potentially be released to the atmosphere if all of the carbon were converted to CO_2. The carbon content coefficients used by the United States are presented in Annex A.

3. *Subtract the amount of carbon stored in products*. Non-fuel uses of fossil fuels can result in storage of some or all of the carbon contained in the fuel for some period of time, depending on the end-use. For example, asphalt made from petroleum can sequester up to 100 percent of the carbon for extended periods of time, while other products, such as lubricants or plastics, lose or emit some carbon when they are used and/or burned as waste. Aggregate U.S. energy statistics include consumption of fossil fuels for non-energy uses; therefore,

[8] Fuel consumption by U.S. territories (i.e. American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report and contributed 12.6 MMTCE of emissions in 1997.

the portion of carbon sequestered through these uses was subtracted from potential carbon emission estimates. The amount of carbon sequestered or stored in non-energy uses of fossil fuels was based on the best available data on the end-uses and ultimate fate of the various energy products. These non-energy uses occurred in the industrial and transportation sectors and U.S. territories.

4. *Adjust for carbon that does not oxidize during combustion*. Because combustion processes are not 100 percent efficient, some of the carbon contained in fuels is not emitted to the atmosphere. Rather, it remains behind as soot, ash, or other by-products of inefficient combustion. The estimated amount of carbon not oxidized due to inefficiencies during the combustion process was assumed to be 1 percent for petroleum and coal and 0.5 percent for natural gas (see Annex A).

5. *Subtract emissions from international bunker fuels*. According to the IPCC guidelines (IPCC/UNEP/OECD/IEA 1997) emissions from international transport activities, or bunker fuels, should not be included in national totals. Because U.S. energy consumption statistics include these bunker fuels—distillate fuel oil, residual fuel oil, and jet fuel—as part of consumption by the transportation sector, emissions from international transport activities were calculated separately and subtracted from emissions from the transportation sector. The calculations for emissions from bunker fuels follows the same procedures used for emissions from consumption of all fossil fuels (i.e., estimation of consumption, determination of carbon content, and adjustment for the fraction of carbon not oxidized.

6. *Allocate transportation emissions by vehicle type*. Because the transportation end-use sector was the largest direct consumer of fossil fuels in the United States,[9] a more detailed accounting of carbon dioxide emissions is provided. Fuel consumption data by vehicle type and transportation mode were used to allocate emissions by fuel type calculated for the transportation end-use sector. Specific data by vehicle type were not available for 1997; therefore, the 1996 percentage allocations were applied to 1997 fuel consumption data in order to estimate emissions in 1997. Military vehicle jet fuel consumption was assumed to account for the difference between total U.S. jet fuel consumption (as reported by DOE/EIA) and civilian air carrier consumption for both domestic and international flights (as reported by DOT/BTS and BEA).

Data Sources

Data on fuel consumption for the United States and its territories, carbon content of fuels, and percent of carbon sequestered in non-energy uses were obtained directly from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE). Fuel consumption data were obtained primarily from the *Monthly Energy Review* (EIA 1998e) and various EIA databases. U.S. marine bunker fuel consumption data for distillate and residual fuel oil was taken from *Fuel Oil and Kerosene Sales* (EIA 1998c). Marine bunker fuel consumption in U.S. territories was collected from internal EIA databases used to prepare the *International Energy Annual* (EIA 1998d). Jet fuel consumption for aviation international bunkers was taken from *Fuel Cost and Consumption*, which are monthly data releases by the Department of Transportation's Bureau of Transportation Statistics (DOT/BTS 1998), and unpublished data from the Bureau of Economic Analysis (BEA 1998). The data collected by DOT/BTS includes fuel consumed for international commercial flights both originating and terminating in the United States. One-half of this value was assumed to have been purchased in the United States.[10]

IPCC (IPCC/UNEP/OECD/IEA 1997) provided combustion efficiency rates for petroleum and natural gas. Bechtel (1993) provided the combustion efficiency rates for coal. Vehicle type fuel consumption data for the allocation of transportation sector emissions were primarily taken from the *Transportation Energy Databook* prepared by the Center for Transportation Analysis at Oak Ridge National Laboratory (DOE 1993, 1994, 1995, 1996, 1997, 1998). All jet fuel and aviation gasoline were assumed to have been consumed in aircraft.

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[9] Electric utilities are not considered a final end-use sector, because they consume energy solely to provide electricity to the other sectors.

[10] See section titled International Bunker Fuels for a more detailed discussion.

Carbon intensity estimates were developed using nuclear and renewable energy data from EIA (1998a) and fossil fuel consumption data as discussed above and presented in Annex A.

For consistency of reporting, the IPCC has recommended that national inventories report energy data (and emissions from energy) using the International Energy Agency (IEA) reporting convention and/or IEA data. Data in the IEA format are presented "top down"—that is, energy consumption for fuel types and categories are estimated from energy production data (accounting for imports, exports, stock changes, and losses). The resulting quantities are referred to as "apparent consumption." The data collected in the United States by EIA, and used in this inventory, are, instead, "bottom up" in nature. In other words, they are collected through surveys at the point of delivery or use and aggregated to determine national totals.

Uncertainty

For estimates of CO_2 from fossil fuel combustion, the amount of CO_2 emitted, in principle is directly related to the amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. Therefore, a careful accounting of fossil fuel consumption by fuel type, average carbon contents of fossil fuels consumed, and consumption of products with long-term carbon storage should yield an accurate estimate of CO_2 emissions.

There are uncertainties, however, concerning the consumption data sources, carbon content of fuels and products, and combustion efficiencies. For example, given the same primary fuel type (e.g., coal), the amount of carbon contained in the fuel per unit of useful energy can vary. Non-energy uses of the fuel can also create situations where the carbon is not emitted to the atmosphere (e.g., plastics, asphalt, etc.) or is emitted at a delayed rate. The proportions of fuels used in these non-fuel production processes that result in the sequestration of carbon have been assumed. Additionally, inefficiencies in the combustion process, which can result in ash or soot remaining unoxidized for long periods, were also assumed. These factors all contribute to the uncertainty in the CO_2 estimates.

Other sources of uncertainty are fuel consumption by U.S. territories and bunker fuels consumed by the military. The United States does not collect as detailed energy statistics for its territories as for the fifty states and the District of Columbia. Therefore both estimating emissions and bunker fuel consumption by these territories is difficult. It is also difficult to determine the geographic boundaries of where military bunker fuels are consumed. The U.S. Department of Defense currently does not collect energy consumption data sufficiently detailed to estimate military bunker fuel emissions.

For the United States, however, these uncertainties are believed to be relatively small. U.S. CO_2 emission estimates from fossil fuel combustion are considered accurate within one or two percent. See, for example, Marland and Pippin (1990).

Stationary Sources (excluding CO_2)

Stationary sources encompass all fuel combustion activities except those related to transportation activities (i.e., mobile combustion). Other than carbon dioxide (CO_2), which was addressed in the previous section, gases from stationary combustion include the greenhouse gases methane (CH_4) and nitrous oxide (N_2O) and the criteria pollutants nitrogen oxides (NO_x), carbon monoxide (CO), and non-methane volatile organic compounds (NMVOCs). Emissions of these gases from stationary sources depend upon fuel characteristics, technology type, usage of pollution control equipment, and ambient environmental conditions. Emissions also vary with the size and vintage of the combustion technology as well as maintenance and operational practices.

Nitrous oxide and NO_x emissions from stationary combustion are closely related to air-fuel mixes and combustion temperatures, as well as the characteristics of any pollution control equipment that is employed. Carbon monoxide emissions from stationary combustion are generally a function of the efficiency of combustion and the use of emission controls; they are highest when less oxygen is present in the air-fuel mixture than is necessary for complete combustion. These conditions are most likely to occur during start-up and shut-down and during fuel switching (e.g., the switching of coal grades at a coal-burning electric utility plant). Methane and NMVOC emissions from stationary combustion are believed to be a function of the CH_4 content of the fuel and post-combustion controls.

Emissions of CH_4 increased slightly from 1990 to 1996, but fell below the 1990 level in 1997 to 2.2 MMTCE (391 Gg). This decrease in emissions was primarily due to lower wood consumption in the residential and commercial sectors. Nitrous oxide emissions rose 8 percent since 1990 to 4.1 MMTCE (49 Gg) in 1997. The largest source of N_2O emissions was coal combustion by electric utilities, which alone accounted for 53 percent of total N_2O emissions from stationary combustion in 1997. Overall, though, stationary combustion is a small source of CH_4 and N_2O in the United States.

In general, stationary combustion was a significant source of NO_x and CO emissions, and a smaller source of NMVOCs. In 1997, emissions of NO_x from stationary combustion represented 46 percent of national NO_x emissions, while CO and NMVOC emissions from stationary combustion contributed approximately 6 and 5 percent, respectively, to the national totals for the same year. From 1990 to 1997, emissions of NO_x were fairly constant, while emissions of CO and NMVOCs decreased by 13 and 14 percent, respectively.

The decrease in CO and NMVOC emissions from 1990 to 1997 can largely be attributed to decreased residential and commercial wood consumption, which is the most significant source of these pollutants in the Energy sector. Overall, NO_x emissions from energy varied due to fluctuations in emissions from electric utilities. Table 2-12, Table 2-13, Table 2-14, and Table 2-15 provide CH_4 and N_2O emission estimates from stationary sources by sector and fuel type. Estimates of NO_x, CO, and NMVOC emissions in 1997 are given in Table 2-16.[11]

Methodology

Methane and nitrous oxide emissions were estimated by multiplying emission factors (by sector and fuel type) by fossil fuel and wood consumption data. Methane and nitrous oxide emission estimates for stationary combustion activities were grouped into four sectors—industrial, commercial/institutional, residential, and electric utilities—and were based on national coal, natural gas, fuel oil, and wood consumption data.

For NO_x, CO, and NMVOCs, the major source categories included in this section are those used in EPA (1998): coal, fuel oil, natural gas, wood, other fuels (including LPG, coke, coke oven gas, and others), and stationary internal combustion. The EPA estimates emissions of NO_x, CO, and NMVOCs by sector and fuel source using a "bottom-up" estimating procedure. In other words, emissions were calculated either for individual sources (e.g., industrial boilers) or for multiple sources combined, using basic activity data as indicators of emissions. Depending on the source category, these basic activity data may include fuel consumption, fuel deliveries, tons of refuse burned, raw material processed, etc.

The EPA derived the overall emission control efficiency of a source category from published reports, the 1985 National Acid Precipitation and Assessment Program (NAPAP) emissions inventory, and other EPA databases. The U.S. approach for estimating emissions of NO_x, CO, and NMVOCs from stationary source combustion, as described above, is similar to the methodology recommended by the IPCC (IPCC/UNEP/OECD/IEA 1997).

More detailed information on the methodology for calculating emissions from stationary sources including emission factors and activity data is provided in Annex B.

Data Sources

Emissions estimates for NO_x, CO, and NMVOCs in this section were taken directly from the EPA's *Draft National Air Pollutant Emissions Trends: 1900 - 1997* (EPA 1998). U.S. energy data were provided by the U.S. Energy Information Administration's *Annual Energy Review* (EIA 1998a) and *Monthly Energy Review* (EIA 1998b). Emission factors were provided by *the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997).

[11] See Annex B for a complete time series of criteria pollutant emission estimates for 1990 through 1997.

Table 2-12: CH_4 Emissions from Stationary Sources (MMTCE)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997
Electric Utilities	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Fuel Oil	+	+	+	+	+	+	+	+
Natural gas	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+
Industrial	**0.8**	**0.8**	**0.8**	**0.8**	**0.9**	**0.9**	**0.9**	**0.9**
Coal	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural gas	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Wood	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.3
Commercial/Institutional	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	0.1	+	+	+	+	+	+	+
Natural gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood*	NA	NA	NA	NA	NA	NA	NA	NA
Residential	**1.3**	**1.3**	**1.4**	**1.3**	**1.3**	**1.4**	**1.4**	**1.1**
Coal	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.9	1.0	1.1	1.0	0.9	1.0	1.1	0.8
Total	**2.3**	**2.4**	**2.4**	**2.4**	**2.4**	**2.5**	**2.5**	**2.2**

+ Does not exceed 0.05 MMTCE
NA (Not Available)
* Commercial/institutional emissions from the combustion of wood are included under the residential sector.
Note: Totals may not sum due to independent rounding.

Table 2-13: N_2O Emissions from Stationary Sources (MMTCE)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997
Electric Utilities	**2.0**	**2.0**	**2.0**	**2.1**	**2.1**	**2.1**	**2.2**	**2.3**
Coal	1.9	1.9	1.9	2.0	2.0	2.0	2.1	2.2
Fuel Oil	0.1	0.1	+	0.1	+	+	+	+
Natural gas	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+
Industrial	**1.4**	**1.4**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**
Coal	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Oil	0.4	0.4	0.4	0.4	0.5	0.4	0.5	0.5
Natural gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Commercial/Institutional	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	+	+	+	+	+	+	+	+
Natural gas	+	+	+	+	+	+	+	+
Wood*	NA	NA	NA	NA	NA	NA	NA	NA
Residential	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Natural Gas	+	+	+	+	+	+	+	+
Wood	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**3.81**	**3.78**	**3.85**	**3.93**	**3.97**	**3.96**	**4.13**	**4.13**

+ Does not exceed 0.05 MMTCE
NA (Not Available)
* Commercial/institutional emissions from the combustion of wood are included under the residential sector.
Note: Totals may not sum due to independent rounding.

Table 2-14: CH_4 Emissions from Stationary Sources (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997
Electric Utilities	**23**	**23**	**22**	**23**	**23**	**23**	**23**	**24**
Coal	16	16	16	17	17	17	18	19
Fuel Oil	4	4	3	3	3	2	2	2
Natural gas	3	3	3	3	3	3	3	3
Wood	1	1	1	1	1	+	1	1
Industrial	**140**	**138**	**143**	**146**	**149**	**149**	**154**	**151**
Coal	27	26	25	25	25	24	24	23
Fuel Oil	17	16	17	17	18	17	18	19
Natural gas	40	41	43	45	46	48	49	49
Wood	55	55	58	59	61	59	63	61
Commercial/Institutional	**23**	**23**	**23**	**23**	**23**	**23**	**24**	**24**
Coal	1	1	1	1	1	1	1	1
Fuel Oil	9	9	8	8	8	8	7	7
Natural gas	13	13	14	14	14	15	15	16
Wood*	NA	NA	NA	NA	NA	NA	NA	NA
Residential	**218**	**227**	**237**	**224**	**220**	**236**	**240**	**191**
Coal	19	17	17	17	17	16	17	17
Fuel Oil	13	13	13	14	13	14	14	15
Natural Gas	21	22	23	24	24	24	26	24
Wood	166	175	184	169	166	183	183	135
Total	**404**	**410**	**425**	**415**	**414**	**431**	**441**	**391**

+ Does not exceed 0.5 Gg
NA (Not Available)
* Commercial/institutional emissions from the combustion of wood are included under the residential sector.
Note: Totals may not sum due to independent rounding.

Table 2-15: N_2O Emissions from Stationary Sources (Gg)

Sector/Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997
Electric Utilities	**24**	**24**	**24**	**25**	**25**	**25**	**26**	**27**
Coal	23	22	23	24	24	24	25	26
Fuel Oil	1	1	1	1	1	+	+	+
Natural gas	+	+	+	+	+	+	+	+
Wood	+	+	+	+	+	+	+	+
Industrial	**17**	**17**	**17**	**17**	**18**	**18**	**18**	**18**
Coal	4	4	3	3	3	3	3	3
Fuel Oil	5	5	5	5	5	5	5	6
Natural gas	1	1	1	1	1	1	1	1
Wood	7	7	8	8	8	8	8	8
Commercial/Institutional	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	1	1	+	+	+	+	+	+
Natural gas	+	+	+	+	+	+	+	+
Wood*	NA	NA	NA	NA	NA	NA	NA	NA
Residential	**3**	**4**	**4**	**4**	**4**	**4**	**4**	**3**
Coal	+	+	+	+	+	+	+	+
Fuel Oil	1	1	1	1	1	1	1	1
Natural Gas	+	+	+	+	+	+	1	+
Wood	2	2	2	2	2	2	2	2
Total	**45**	**45**	**46**	**46**	**47**	**47**	**49**	**49**

+ Does not exceed 0.5 Gg
NA (Not Available)
* Commercial/institutional emissions from the combustion of wood are included under the residential sector.
Note: Totals may not sum due to independent rounding.

Table 2-16: NO_x, CO, and NMVOC Emissions from Stationary Sources in 1997 (Gg)

Sector/Fuel Type	NO_x	CO	NMVOC
Electric Utilities	**5,605**	**368**	**46**
Coal	5,079	230	26
Fuel Oil	120	11	3
Natural gas	262	71	7
Wood	NA	NA	NA
Internal Combustion	144	56	9
Industrial	**2,967**	**1,007**	**197**
Coal	557	91	5
Fuel Oil	218	66	11
Natural gas	1,256	329	70
Wood	NA	NA	NA
Other Fuels[a]	118	288	48
Internal Combustion	818	233	62
Commercial/Institutional	**379**	**235**	**22**
Coal	36	14	1
Fuel Oil	97	17	3
Natural gas	219	51	10
Wood	NA	NA	NA
Other Fuels[a]	27	152	8
Residential	**779**	**2,759**	**515**
Coal[b]	NA	NA	NA
Fuel Oil[b]	NA	NA	NA
Natural Gas[b]	NA	NA	NA
Wood	31	2,520	478
Other Fuels[a]	748	239	37
Total	**9,729**	**4,369**	**780**

NA (Not Available)
[a] "Other Fuels" include LPG, waste oil, coke oven gas, coke, and non-residential wood (EPA 1998).
[b] Coal, fuel oil, and natural gas emissions are included in the "Other Fuels" category (EPA 1998).
Note: Totals may not sum due to independent rounding. See Annex B for emissions in 1990 through 1996.

Uncertainty

Methane emission estimates from stationary sources are highly uncertain, primarily due to difficulties in calculating emissions from wood combustion (i.e., fireplaces and wood stoves). The estimates of CH_4 and N_2O emissions presented are based on broad indicators of emissions (i.e., fuel use multiplied by an aggregate emission factor for different sectors), rather than specific emission processes (i.e., by combustion technology and type of emission control). The uncertainties associated with the emission estimates of these gases are greater than with estimates of CO_2 from fossil fuel combustion, which are mainly a function of the carbon content of the fuel combusted. Uncertainties in both CH_4 and N_2O estimates are due to the fact that emissions are estimated based on emission factors representing only a limited subset of combustion conditions. For the criteria pollutants, uncertainties are partly due to assumptions concerning combustion technology types, age of equipment, emission factors used, and projections of growth.

Mobile Sources (excluding CO_2)

Mobile sources emit greenhouse gases other than CO_2, including methane (CH_4), nitrous oxide (N_2O), and the criteria pollutants carbon monoxide (CO), nitrogen oxides (NO_x), and non-methane volatile organic compounds (NMVOCs).

As with combustion in stationary sources, N_2O and NO_x emissions are closely related to fuel characteristics, air-fuel mixes, and combustion temperatures, as well as usage of pollution control equipment. Nitrous oxide, in particular, can be formed by the catalytic processes used to control NO_x and CO emissions. Carbon monoxide emissions from mobile source combustion are significantly affected by combustion efficiency and presence of post-combustion emission controls. Carbon monoxide emissions are highest when air-fuel mixtures have less oxygen than required for complete combustion. This occurs especially in idle, low speed and cold start conditions. Methane and NMVOC emissions from motor vehicles are a function of the CH_4 content of the motor fuel, the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions, such as catalytic converters.

Emissions from mobile sources were estimated by transport mode (e.g., highway, air, rail, and water) and fuel type—motor gasoline, diesel fuel, jet fuel, aviation gas, natural gas, liquefied petroleum gas (LPG), and residual fuel oil—and vehicle type. Road transport accounted for the majority of mobile source fuel consumption, and hence, the majority of mobile source emissions. Table 2-17 through Table 2-20 provide CH_4 and N_2O emission estimates from mobile sources by vehicle type, fuel type, and transport mode. Estimates of NO_x, CO, and NMVOC emissions in 1997 are given in Table 2-21.[12]

[12] See Annex C for a complete time series of criteria pollutant emission estimates for 1990 through 1997.

Table 2-17: CH_4 Emissions from Mobile Sources (MMTCE)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997
Gasoline Highway	**1.3**	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**	**1.2**
Passenger Cars	0.8	0.7	0.7	0.7	0.7	0.7	0.6	0.6
Light-Duty Trucks	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
Heavy-Duty Vehicles	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Motorcycles	+	+	+	+	+	+	+	+
Diesel Highway	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Passenger Cars	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Non-Highway	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Ships and Boats	+	+	+	+	+	+	+	+
Locomotives	+	+	+	+	+	+	+	+
Farm Equipment	+	+	+	+	+	+	+	+
Construction Equipment	+	+	+	+	+	+	+	+
Aircraft	+	+	+	+	+	+	+	+
Other*	+	+	+	+	+	+	+	+
Total	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**

+ Does not exceed 0.05 MMTCE
Note: Totals may not sum due to independent rounding.
* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-18: N_2O Emissions from Mobile Sources (MMTCE)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997
Gasoline Highway	**12.3**	**12.9**	**13.8**	**14.6**	**15.3**	**15.6**	**16.0**	**16.1**
Passenger Cars	8.6	9.0	9.7	10.1	9.9	10.1	8.9	9.0
Light-Duty Trucks	3.4	3.7	3.9	4.2	5.1	5.2	6.8	6.7
Heavy-Duty Vehicles	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Motorcycles	+	+	+	+	+	+	+	+
Diesel Highway	**0.5**	**0.5**	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**
Passenger Cars	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6
Non-Highway	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**
Ships and Boats	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Locomotives	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Farm Equipment	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Construction Equipment	+	+	+	+	+	+	+	+
Aircraft	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Other*	+	+	+	+	+	+	+	+
Total	**13.6**	**14.2**	**15.2**	**15.9**	**16.7**	**17.0**	**17.4**	**17.5**

+ Does not exceed 0.05 MMTCE
Note: Totals may not sum due to independent rounding.
* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-19: CH_4 Emissions from Mobile Sources (Gg)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997
Gasoline Highway	**220**	**214**	**211**	**209**	**211**	**209**	**212**	**210**
Passenger Cars	133	128	127	123	115	114	98	100
Light-Duty Trucks	67	66	65	66	75	74	94	91
Heavy-Duty Vehicles	16	16	15	16	17	17	16	16
Motorcycles	4	4	4	4	4	4	4	4
Diesel Highway	**10**	**10**	**10**	**11**	**11**	**11**	**12**	**12**
Passenger Cars	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	10	10	10	10	11	11	11	11
Non-Highway	**22**	**21**	**21**	**21**	**21**	**22**	**22**	**20**
Ships and Boats	4	4	4	4	4	4	4	3
Locomotives	3	2	3	2	2	3	3	2
Farm Equipment	6	5	6	5	6	6	6	6
Construction Equipment	1	1	1	1	1	1	1	1
Aircraft	8	7	7	7	7	7	7	7
Other*	1	1	1	1	1	1	1	1
Total	**252**	**245**	**243**	**241**	**244**	**242**	**246**	**242**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding.
* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-20: N_2O Emissions from Mobile Sources (Gg)

Fuel Type/Vehicle Type	1990	1991	1992	1993	1994	1995	1996	1997
Gasoline Highway	**145**	**153**	**164**	**173**	**181**	**184**	**189**	**191**
Passenger Cars	102	107	115	120	117	119	105	107
Light-Duty Trucks	41	44	46	50	60	61	80	80
Heavy-Duty Vehicles	2	3	3	3	3	4	4	4
Motorcycles	+	+	+	+	+	+	+	+
Diesel Highway	**6**	**6**	**6**	**6**	**7**	**7**	**7**	**7**
Passenger Cars	+	+	+	+	+	+	+	+
Light-Duty Trucks	+	+	+	+	+	+	+	+
Heavy-Duty Vehicles	5	5	6	6	6	6	7	7
Non-Highway	**10**	**9**	**10**	**9**	**10**	**10**	**10**	**9**
Ships and Boats	1	1	1	1	1	2	1	1
Locomotives	1	1	1	1	1	1	1	1
Farm Equipment	1	1	1	1	1	1	1	1
Construction Equipment	+	+	+	+	+	+	+	+
Aircraft	6	6	5	5	6	6	6	6
Other*	+	+	+	+	+	+	+	+
Total	**161**	**169**	**179**	**188**	**197**	**201**	**206**	**207**

+ Does not exceed 0.5 Gg
Note: Totals may not sum due to independent rounding.
* "Other" includes snowmobiles, small gasoline powered utility equipment, heavy-duty gasoline powered utility equipment, and heavy-duty diesel powered utility equipment.

Table 2-21: NO_x, CO, and NMVOC Emissions from Mobile Sources in 1997 (Gg)

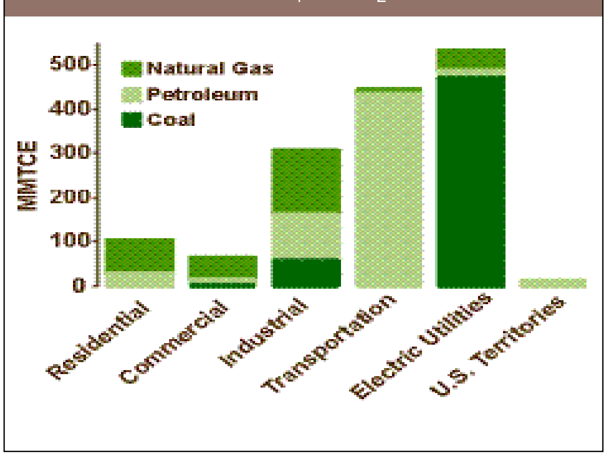
Fuel Type/Vehicle Type	NO_x	CO	NMVOCs
Gasoline Highway	**4,629**	**44,225**	**4,528**
Passenger Cars	2,597	24,356	2,467
Light-Duty Trucks	1,725	16,659	1,785
Heavy-Duty Vehicles	296	3,039	243
Motorcycles	11	171	33
Diesel Highway	**1,753**	**1,368**	**217**
Passenger Cars	31	27	11
Light-Duty Trucks	11	10	5
Heavy-Duty Vehicles	1,711	1,332	201
Non-Highway	**4,137**	**15,201**	**2,205**
Ships and Boats	273	1,704	468
Locomotives	861	105	45
Farm Equipment	962	298	116
Construction Equipment	1,120	1,080	219
Aircraft[a]	161	918	170
Other[b]	759	11,096	1,186
Total	**10,519**	**60,794**	**6,949**

[a] Aircraft estimates include only emissions related to LTO cycles, and therefore do not include cruise altitude emissions.
[b] "Other" includes gasoline powered recreational, industrial, lawn and garden, light commercial, logging, airport service, other equipment; and diesel powered recreational, industrial, lawn and garden, light construction, airport service.
Note: Totals may not sum due to independent rounding. See Annex C for emissions in 1990 through 1996.

Mobile sources were responsible for a small portion of national CH_4 emissions but were the second largest source of N_2O in the United States. From 1990 to 1997, CH_4 emissions declined by 4 percent, to 1.4 MMTCE (242 Gg). Nitrous oxide emissions, however, rose 29 percent to 17.5 MMTCE (207 Gg) (see Figure 2-12). The reason for this conflicting trend was that the control technologies employed on highway vehicles in the United States lowered CO, NO_x, NMVOC, and CH_4 emissions, but resulted in higher average N_2O emission rates. Fortunately, since 1994 improvements in the emission control technologies installed on new vehicles have reduced emission rates of both NO_x and N_2O per vehicle mile traveled. Overall, CH_4 and N_2O emissions were dominated by gasoline-fueled passenger cars and light-duty gasoline trucks.

Figure 2-12

Mobile Source CH_4 and N_2O Emissions



Emissions of criteria pollutants generally increased from 1990 through 1994, after which there were decreases of 4 (NO_x) to 14 (CO) percent by 1997. A drop in gasoline prices combined with a strengthening U.S. economy caused the initial increase. These factors pushed the vehicle miles traveled (VMT) by road sources up, resulting in increased fuel consumption and higher emissions. Some of this increased activity was later offset by an increasing portion of the U.S. vehicle fleet meeting established emissions standards.

Fossil-fueled motor vehicles comprise the single largest source of CO emissions in the United States and are a significant contributor to NO_x and NMVOC emissions. In 1997, CO emissions from mobile sources contributed 81 percent of total CO emissions and 49 and 41 percent of NO_x and NMVOC emissions, respectively. Since 1990, emissions of CO and NMVOCs from mobile sources decreased by 8 and 13 percent, respectively, while emissions of NO_x increased by 3 percent.

Methodology

Estimates for CH_4 and N_2O emissions from mobile combustion were calculated by multiplying emission factors by measures of activity for each category. Depending upon the category, activity data included such information as fuel consumption, fuel deliveries, and vehicle miles traveled (VMT). Emission estimates from highway vehicles were based on VMT and emission factors by vehicle type, fuel type, model year, and control technology. Fuel consumption data was employed as a measure of activity for non-highway vehicles and then fuel-specific emission factors were applied.[13] A complete discussion of the methodology used to estimate emissions from mobile sources is provided in Annex C.

The EPA (1998a) provided emissions estimates of NO_x, CO, and NMVOCs for eight categories of highway vehicles[14], aircraft, and seven categories of off-highway vehicles[15].

Data Sources

Emission factors used in the calculations of CH_4 and N_2O emissions are presented in Annex C. The *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997) provided emission factors for CH_4, and were developed using MOBILE5a, a model used by the Environmental Protection Agency (EPA) to estimate exhaust and running loss emissions from highway vehicles. The MOBILE5a model uses information on ambient temperature, vehicle speeds, national vehicle registration distributions, gasoline volatility, and other variables in order to produce these factors (EPA 1997).

Emission factors for N_2O from gasoline highway vehicles came from a recent EPA report (1998b). This report developed emission factors for older passenger cars (roughly pre-1992 in California and pre-1994 in the rest of the United States), from published references, and for newer cars from a recent testing program at EPA's National Vehicle and Fuel Emissions Laboratory (NVFEL). These emission factors for gasoline highway vehicles are lower than the U.S. default values in the *Revised 1996 IPCC Guidelines*, but are higher than the European default values, both of which were published before the more recent tests and literature review conducted by the NVFEL. The U.S. default values in the *Revised 1996 IPCC Guidelines* were based on three studies that tested a total of five cars using European rather than U.S. test protocols. More details may be found in EPA (1998b).

Emission factors for gasoline vehicles other than passenger cars were scaled from those for passenger cars with the same control technology, based on their relative fuel economy. This scaling was supported by limited data showing that light-duty trucks emit more N_2O than passenger cars with equivalent control technology. The use of fuel-consumption ratios to determine emission factors is considered a temporary measure only, to be replaced as soon as additional testing data are available. For more details, see EPA (1998b). Nitrous oxide emission factors for diesel highway vehicles were taken from the European default values found in the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). There is little data addressing N_2O emissions from U.S. diesel-fueled vehicles, and in general, European countries have had more experience with diesel-fueled vehicles. U.S. default values in the *Revised 1996 IPCC Guidelines* were used for non-highway vehicles.

Activity data were gathered from several U.S. government sources including EIA (1998a), EIA (1998b), FHWA (1998), BEA (1998), DOC (1998) FAA (1998), and DOT/BTS (1998). Control technology data for highway vehicles were obtained from the EPA's Office of Mobile Sources. Annual VMT data for 1990 through 1997 were obtained from the Federal Highway Administration's (FHWA) Highway Performance Monitoring System database, as noted in EPA (1998a).

Emissions estimates for NO_x, CO, NMVOCs were taken directly from the EPA's *National Air Pollutant Emissions Trends, 1900 - 1997* (EPA 1998a).

Uncertainty

Mobile source emission estimates can vary significantly due to assumptions concerning fuel type and composition, technology type, average speeds, type of emission control equipment, equipment age, and operating and maintenance practices. Fortunately, detailed activity data for mobile sources were available, includ-

[13] The consumption of international bunker fuels is not included in these activity data, but are estimated separately under the International Bunker Fuels source category.

[14] These categories included: gasoline passenger cars, diesel passenger cars, light-duty gasoline trucks less than 6,000 pounds in weight, light-duty gasoline trucks between 6,000 and 8,500 pounds in weight, light-duty diesel trucks, heavy-duty gasoline trucks and buses, heavy-duty diesel trucks and buses, and motorcycles.

[15] These categories included: gasoline and diesel farm tractors, other gasoline and diesel farm machinery, gasoline and diesel construction equipment, snowmobiles, small gasoline utility engines, and heavy-duty gasoline and diesel general utility engines.

ing VMT by vehicle type for highway vehicles. The allocation of this VMT to individual model years was done using the profile of U.S. vehicle usage by vehicle age in 1990 as specified in MOBILE 5a. Data to develop a temporally variable profile of vehicle usage by model year instead of age was not available.

Average emission factors were developed based on numerous assumptions concerning the age and model of vehicle; percent driving in cold start, warm start, and cruise conditions; average driving speed; ambient temperature; and maintenance practices. The factors for regulated emissions from mobile sources—CO, NO_x, and hydrocarbons—have been extensively researched, and thus involve lower uncertainty than emissions of unregulated gases. Although methane has not been singled out for regulation in the United States, overall hydrocarbon emissions from mobile sources—a component of which is methane—are regulated.

Compared to methane, CO, NO_x, and NMVOCs, there is relatively little data available to estimate emission factors for nitrous oxide. Nitrous oxide is not a criteria pollutant, and measurements of it in automobile exhaust have not been routinely collected. Research data has shown that N_2O emissions from vehicles with catalytic converters are greater than those without emission controls, and that vehicles with aged catalysts emit more than new ones. The emission factors used were, therefore, derived from aged cars (EPA 1998b). The emission factors used for Tier 0 and older cars were based on tests of 28 vehicles; those for newer vehicles were based on tests of 22 vehicles. This sample is small considering that it is being used to characterize the entire U.S. fleet, and the associated uncertainty is therefore large. Currently, N_2O gasoline highway emission factors for vehicles other than passenger cars are scaled based on those for passenger cars and their relative fuel economy. Actual measurements should be substituted for this procedure when they become available. Further testing is needed to reduce the uncertainty in emission factors for all classes of vehicles, using realistic driving regimes, environmental conditions, and fuels.

Although aggregate jet fuel and aviation gasoline consumption data has been used to estimate emissions from aircraft, the recommended method for estimating emissions in the *Revised 1996 IPCC Guidelines* is to use data by specific aircraft type (IPCC/UNEP/OECD/IEA 1997). The IPCC also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate near-ground level emissions. The EPA is attempting to develop revised estimates based on this more detailed activity data, and these estimates are to be presented in future inventories.

U.S. jet fuel and aviation gasoline consumption is currently all attributed to the transportation sector by EIA, and it is assumed here that it is all used to fuel aircraft. However it is likely that some fuel purchased by airlines is not necessarily be used in aircraft, but instead used to power auxiliary power units, in ground equipment, and to test engines. Some jet fuel may also be used for other purposes such as blending with diesel fuel or heating oil.

Overall, uncertainty for N_2O emissions estimates is considerably higher than for CH_4, CO, NO_x, or NMVOC; however, all these gases involve far more uncertainty than CO_2 emissions from fossil fuel combustion.

Lastly, in EPA (1998), U.S. aircraft emission estimates for CO, NOx, and NMVOCs are based upon landing and take-off (LTO) cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates presented here overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including LTO cycles by aircraft on international flights but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes.

Coal Mining

All underground and surface coal mining liberates (i.e., releases) methane as part of normal operations. The amount of methane liberated during mining is primarily dependent upon the amount of methane stored in the coal and the surrounding strata. This *in situ* methane content is a function of the quantity of methane generated during the coal formation process and its ability to migrate through the surrounding strata over time. The degree of coalification—defined by the rank or quality of the coal formed—determines the amount of methane generated during the coal formation process; higher ranked coals generate more methane. The amount of methane that remains in the coal and surrounding strata also depends upon geologic characteristics such as pressure within a coal seam. Deeper coal deposits tend to retain more of the methane generated during coalification. Accordingly, deep underground coal seams generally have higher methane contents than shallow coal seams or surface deposits.

Underground, versus surface, coal mines contribute the largest share of methane emissions. All underground coal mines employ ventilation systems to ensure that methane levels remain within safe concentrations. These systems can exhaust significant amounts of methane to the atmosphere in low concentrations. Additionally, over twenty gassy U.S. coal mines supplement ventilation systems with degasification systems. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of methane before or after mining. In 1997, 14 coal mines collected methane from degasification systems and sold this gas to a pipeline, thus reducing emissions to the atmosphere. Surface coal mines also release methane as the overburden is removed and the coal is exposed. Additionally, after coal has been mined, small amounts of methane retained in the coal are released during processing, storage, and transport.

Total methane emissions in 1997 were estimated to be 18.8 MMTCE (3.3 Tg), declining 22 percent since 1990 (see Table 2-22 and Table 2-23). Of this amount, underground mines accounted for 65 percent, surface mines accounted for 14 percent, and post-mining emissions accounted for 21 percent. With the exception of 1995, total methane emissions declined every year during this period. In 1993, emissions from underground mining dropped to a low of 2.8 Tg, primarily due to labor strikes at many of the large underground mines. In 1995, there was an increase in methane emissions from underground mining due to particularly high emissions at the gassiest coal mine in the country. Overall, with the exception of 1995, total methane emitted from underground mines declined in each year because of increased gas recovery and use. Surface mine emissions and post-mining emissions remained relatively constant from 1990 to 1997.

In 1994, EPA's Coalbed Methane Outreach Program (CMOP) began working with the coal industry and

Table 2-22: CH_4 Emissions from Coal Mining (MMTCE)

Activity	1990	1991	1992	1993	1994	1995	1996	1997
Underground Mining	17.1	16.4	15.6	13.3	13.1	14.2	12.6	12.3
Liberated	18.8	18.1	17.8	16.0	16.3	17.7	16.5	16.8
Recovered & Used	(1.6)	(1.7)	(2.1)	(2.7)	(3.2)	(3.4)	(3.8)	(4.6)
Surface Mining	2.8	2.6	2.6	2.5	2.6	2.4	2.5	2.6
Post- Mining (Underground)	3.6	3.4	3.3	3.0	3.3	3.3	3.4	3.5
Post-Mining (Surface)	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	**24.0**	**22.8**	**22.0**	**19.2**	**19.4**	**20.3**	**18.9**	**18.8**

Note: Totals may not sum due to independent rounding.

Table 2-23: CH_4 Emissions from Coal Mining (Tg)

Activity	1990	1991	1992	1993	1994	1995	1996	1997
Underground Mining	3.0	2.9	2.7	2.3	2.3	2.5	2.2	2.1
Liberated	3.3	3.2	3.1	2.8	2.8	3.1	2.9	2.9
Recovered & Used	(0.3)	(0.3)	(0.4)	(0.5)	(0.6)	(0.6)	(0.7)	(0.8)
Surface Mining	0.5	0.4	0.4	0.4	0.5	0.4	0.4	0.5
Post- Mining (Underground)	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.6
Post-Mining (Surface)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**4.2**	**4.0**	**3.8**	**3.4**	**3.4**	**3.6**	**3.3**	**3.3**

Note: Totals may not sum due to independent rounding.

other stakeholders to identify and remove obstacles to investments in coal mine methane recovery and use projects. Reductions attributed to CMOP were estimated to be 0.7, 0.8, 1.0, and 1.3 MMTCE in 1994, 1995, 1996 and 1997, respectively.

Methodology

The methodology for estimating methane emissions from coal mining consists of two main steps. The first step involved estimating methane emissions from underground mines. Because of the availability of ventilation system measurements, underground mine emissions can be estimated on a mine-by-mine basis and then summed to determine total emissions. The second step involved estimating emissions from surface mines and post-mining activities by multiplying basin-specific coal production by basin-specific emissions factors.

Underground mines. Total methane emitted from underground mines was estimated as the quantity of methane liberated from ventilation systems, plus methane liberated from degasification systems, minus methane recovered and used. The Mine Safety and Heath Administration (MSHA) measures methane emissions from ventilation systems for all mines with detectable[16] methane concentrations. These mine-by-mine measurements were used to estimate methane emissions from ventilation systems.

Some of the gassier underground mines also use degasification systems (e.g., wells or boreholes) that remove methane before or after mining . This methane can then be collected for use or vented to the atmosphere. Various approaches were employed to estimate the quantity of methane collected by each of the more than twenty mines using these systems, depending on available data. For example, some mines have reported to EPA the amounts of methane liberated from their degasification systems. For mines that sell recovered methane to a pipeline, pipeline sales data was used to estimate degasification emissions. Finally, for those mines for which no other data was available, default recovery efficiency values were developed, depending on the type of degasification system employed.

Finally, the amount of methane recovered by degasification systems and then used (i.e., not vented) was estimated. This calculation was complicated by the fact that methane is rarely recovered and used during the same year in which the particular coal seam is mined. In 1997, 14 active coal mines sold recovered methane to a pipeline operator. Emissions avoided for these projects were estimated using gas sales data reported by various state agencies, and information supplied by coal mine operators regarding the number of years in advance of mining that gas recovery occurred. Additionally, some of the state agencies provided individual well production information, which was used to assign gas sales to a particular year.

Surface Mines and Post-Mining Emissions. Surface mining and post-mining methane emissions were estimated by multiplying basin-specific coal production by basin-specific emissions factors. For surface mining, emissions factors were developed by assuming that surface mines emit from one to three times as much methane as the average *in situ* methane content of the coal. This accounts for methane released from the strata surrounding the coal seam. For this analysis, it is assumed that twice the average *in-situ* methane content is emitted. For post-mining emissions, the emission factor was assumed to be from 25 to 40 percent of the average *in situ* methane content of coals mined in the basin. For this analysis, it is assumed that 32.5 percent of the average *in-situ* methane content is emitted.

Data Sources

The Mine Safety and Health Administration provided mine-specific information on methane liberated from ventilation systems at underground mines. EPA developed estimates of methane liberated from degasification systems at underground mines based on available data for each of the mines employing these systems. The primary sources of data for estimating

[16] MSHA records coal mine methane readings with concentrations of greater than 50 ppm (parts per million) methane. Readings below this threshold are considered non-detectable.

emissions avoided at underground mines were gas sales data published by state petroleum and natural gas agencies, information supplied by mine operators regarding the number of years in advance of mining that gas recovery occurred, and reports of gas used on-site. Annual coal production data was taken from the Energy Information Agency's *Coal Industry Annual* (see Table 2-24) (EIA 1991, 1992, 1993, 1994, 1995, 1996, 1997, 1998). Data on *in situ* methane content and emissions factors were taken from EPA (1993).

Table 2-24: Coal Production (Thousand Metric Tons)

Year	Underground	Surface	Total
1990	384,247	546,814	931,061
1991	368,633	532,653	901,285
1992	368,625	534,286	902,911
1993	318,476	539,211	857,687
1994	362,063	575,525	937,588
1995	359,475	577,634	937,109
1996	371,813	593,311	965,125
1997	381,620	607,163	988,783

Uncertainty

The emission estimates from underground ventilation systems were based upon actual measurement data for mines with detectable methane emissions. Accordingly, the uncertainty associated with these measurements is estimated to be low. Estimates of methane liberated from degasification systems are less certain because EPA assigns default recovery efficiencies for a subset of U.S. mines. Compared to underground mines, there is considerably more uncertainty associated with surface mining and post-mining emissions because of the difficulty in developing accurate emissions factors from field measurements. Because underground emissions comprise the majority of total coal mining emissions, the overall uncertainty is estimated to be only ±15 percent.[17] Currently, the estimate does not include emissions from abandoned coal mines because of limited data. The EPA is conducting research on the feasibility of including an estimate in future years.

Natural Gas Systems

Methane emissions from natural gas systems are generally process related, with normal operations, routine maintenance, and system upsets being the primary contributors. Emissions from normal operations include: natural gas combusting engine and turbine exhaust, bleed and discharge emissions from pneumatic devices, and fugitive emissions from system components. Routine maintenance emissions originate from pipelines, equipment, and wells during repair and maintenance activities. Pressure surge relief systems and accidents can lead to system upset emissions.

The U.S. natural gas system encompasses hundreds of thousands of wells, hundreds of processing facilities, hundreds of thousands of miles of transmission pipelines, and over a million miles of distribution pipeline. The system, though, can be divided into four stages, each with different factors affecting methane emissions, as follows:

Field Production. In this initial stage, wells are used to withdraw raw gas from underground formations. Emissions arise from the wells themselves, treatment facilities, gathering pipelines, and process units such as dehydrators and separators. Fugitive emissions and emissions from pneumatic devices accounted for the majority of emissions. Emissions from field production have increased absolutely and as a proportion of total emissions from natural gas systems—approximately 27 percent between 1990 and 1996—due to an increased number of producing gas wells and related equipment, and then leveled off in 1997 at 9.5 MMTCE.

Processing. In this stage, processing plants remove various constituents from the raw gas before it is injected into the transmission system. Fugitive emissions from compressors, including compressor seals, were the primary contributor from this stage. Processing plants accounted for about 12 percent of methane emissions from natural gas systems during the period of 1990 through 1997.

[17] Preliminary estimate

Transmission and Storage. Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production areas to distribution centers or large volume customers. From 1990 to 1997, total natural gas transmission pipeline milage varied, with an overall decline from about 280,000 miles to about 260,000 miles. Throughout the transmission system, compressor stations pressurize the gas to move it through the pipeline. Fugitive emissions from compressor stations and metering and regulating stations accounted for the majority of the emissions from transmission. Pneumatic devices and engine exhaust were smaller sources of emissions from transmission facilities. Methane emissions from the transmission stage accounted for approximately 35 percent of the emissions from natural gas systems.

Natural gas is also injected and stored in underground formations during periods of low demand, and withdrawn, processed, and distributed during periods of high demand. Compressors and dehydrators were the primary contributors from these storage facilities. Less than one percent of total emissions from natural gas systems can be attributed to these facilities.

Distribution. The distribution of natural gas requires the use of low-pressure pipelines to deliver gas to customers. The distribution network consisted of nearly 1.4 million miles of pipeline in 1996, increasing from a 1990 figure of just over 1.3 million miles (AGA 1996). Distribution system emissions, which accounted for approximately 27 percent of emissions from natural gas systems, resulted mainly from fugitive emissions from gate stations and non-plastic piping. An increased use of plastic piping, which has lower emissions than other pipe materials, has reduced the growth in emissions from this stage.

Overall, natural gas systems emitted 33.5 MMTCE (5.9 Tg) of methane in 1997 (see Table 2-25 and Table 2-26). Emissions rose slightly from 1990 to 1997, reflecting an increase in the number of producing gas wells and miles of distribution pipeline. Initiated in 1993, EPA's Natural Gas STAR program is working with the gas industry to promote profitable practices that reduce methane emissions. The program is estimated to have reduced emissions by 0.7, 1.2, 1.3 and 1.6 MMTCE in 1994, 1995, 1996, and 1997, respectively.

Methodology

The foundation for the estimate of methane emissions from the U.S. natural gas industry is a detailed study by the Gas Research Institute and EPA (GRI/EPA 1995). The GRI/EPA study developed over 100 detailed emission factors and activity levels through site visits to selected gas facilities, and arrived at a national point

Table 2-25: CH_4 Emissions from Natural Gas Systems (MMTCE)

Stage	1990	1991	1992	1993	1994	1995	1996	1997
Field Production	8.0	8.2	8.5	8.7	8.8	9.1	9.5	9.5
Processing	4.0	4.0	4.0	4.0	4.2	4.1	4.1	4.1
Transmission and Storage	12.6	12.7	12.9	12.6	12.5	12.5	12.4	12.7
Distribution	8.3	8.4	8.6	8.8	8.7	8.7	9.1	8.9
Total	**32.9**	**33.3**	**33.9**	**34.1**	**33.5**	**33.2**	**33.7**	**33.5**

Note: 1994 through 1997 totals include reductions from Natural Gas STAR program. Totals may not sum due to independent rounding.

Table 2-26: CH_4 Emissions from Natural Gas Systems (Tg)

Stage	1990	1991	1992	1993	1994	1995	1996	1997
Field Production	1.4	1.4	1.5	1.5	1.5	1.6	1.7	1.7
Processing	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Transmission and Storage	2.2	2.2	2.3	2.2	2.2	2.2	2.2	2.2
Distribution	1.4	1.5	1.5	1.5	1.5	1.5	1.6	1.5
Total	**5.7**	**5.8**	**5.9**	**5.9**	**5.8**	**5.8**	**5.9**	**5.9**

Note: 1994 through 1997 totals include reductions from Natural Gas STAR program. Totals may not sum due to independent rounding.

estimate for 1992. Since publication of this study, EPA conducted additional analysis to update the activity data for some of the components of the system, particularly field production equipment. Summing emissions across individual sources in the natural gas system provided a 1992 baseline emission estimate from which the emissions for the period 1990 through 1997 were derived.

Apart from the year 1992, detailed statistics on each of the over 100 activity levels were not available for the time series 1990 through 1997. To estimate these activity levels, aggregate annual statistics were obtained on the main driving variables, including: number of producing wells, number of gas plants, miles of transmission pipeline, miles of distribution pipeline, and miles of distribution services. By assuming that the relationships among these variables remained constant (e.g., the number of heaters per well remained the same), the statistics on these variables formed the basis for estimating other activity levels.

For the period 1990 through 1995, the emission factors were held constant. A gradual improvement in technology and practices is expected to reduce the emission factors slightly over time. To reflect this trend, the emission factors were reduced by about 0.2 percent per year starting with 1996, a rate that, if continued, would lower the emission factors by 5 percent in 2020. See Annex E for more detailed information on the methodology and data used to calculate methane emissions from natural gas systems.

Data Sources

Activity data were taken from the American Gas Association (AGA 1991, 1992, 1993, 1994, 1995, 1996, 1997), the Energy Information Administration's *Annual Energy Outlook* (EIA 1997a), *Natural Gas Annual* (EIA 1997b), and *Natural Gas Monthly* (EIA 1998), and the Independent Petroleum Association of America (IPAA 1997). The U.S. Department of Interior (DOI 1997, 1998) supplied offshore platform data. All emission factors were taken from GRI/EPA (1995).

Uncertainty

The heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry. Because of this, scaling up from model facilities introduces a degree of uncertainty. Additionally, highly variable emission rates were measured among many system components, making the calculated average emission rates uncertain. Despite the difficulties associated with estimating emissions from this source, the uncertainty in the total estimated emissions are believed to be on the order of ±40 percent.

Petroleum Systems

One of the gases emitted from the production and refining of petroleum products is methane. The activities that lead to methane emissions include: production field treatment and separation, routine maintenance of production field equipment, crude oil storage, refinery processes, crude oil tanker loading and unloading, and venting and flaring. Each stage is described below:

Production Field Operations. Fugitive emissions from oil wells and related production field treatment and separation equipment are the primary source of emissions from production fields. From 1990 to 1997, these emissions accounted for about 10 percent of total emissions from petroleum systems. Routine maintenance, which includes the repair and maintenance of valves, piping, and other equipment, accounted for less than 1 percent of total emissions from petroleum systems. Emissions from production fields are expected to decline in the future as the number of oil wells decreases.

Crude Oil Storage. Crude oil storage tanks emit methane during two processes. "Breathing losses" from roof seals and joints occur when the tank is in use, and while tanks are being drained or filled. "Working losses" occur as the methane in the air space above the liquid is displaced. Piping and other equipment at storage facilities can also produce fugitive emissions. Between 1990 and 1997, crude oil storage emissions accounted for less than 1 percent of total emissions from petroleum systems.

Refining. Waste gas streams from refineries are a source of methane emissions. Based on Tilkicioglu and Winters (1989), who extrapolated waste gas stream emissions to national refinery capacity, emissions estimates from this source accounted for approximately 3 percent of total methane emissions from the production and refining of petroleum.

Tanker Operations. The loading and unloading of crude oil tankers releases methane. From 1990 to 1997, emissions from crude oil transportation on tankers accounted for roughly 2 percent of total emissions from petroleum systems.

Venting and Flaring. Gas produced during oil production that cannot be contained or otherwise used is released into the atmosphere or flared. Vented gas typically has a high methane content; however, it is assumed that flaring destroys the majority of the methane in the gas (about 98 percent depending upon the moisture content of the gas). Venting and flaring may account for up to 85 percent of emissions from petroleum systems. There is considerable uncertainty in the estimate of emissions from this activity.

In 1997 methane emissions from petroleum systems were 1.6 MMTCE (271 Gg) and have remained essentially constant since 1990. Emission estimates are provided below in Table 2-27 and Table 2-28.

Methodology

The methodology used for estimating emissions from each stage is described below:

Production Field Operations. Emission estimates were calculated by multiplying emission factors (i.e., emissions per oil well) with their corresponding activity data (i.e., number of oil wells). To estimate emissions for 1990 to 1997, emission factors developed to estimate 1990 emissions were multiplied by updated activity data for 1990 through 1997. Emissions estimates from petroleum systems excluded associated natural gas wells to prevent double counting with the estimates for Natural Gas Systems.

Crude Oil Storage. Tilkicioglu and Winters (1989) estimated crude oil storage emissions on a model tank farm facility with fixed and floating roof tanks. Emission factors developed for the model facility were applied to published crude oil storage data to estimate emissions.

Table 2-27: CH_4 Emissions from Petroleum Systems (MMTCE)

Stage	1990	1991	1992	1993	1994	1995	1996	1997
Production Field Operations	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Crude Oil Storage	+	+	+	+	+	+	+	+
Refining	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Tanker Operations	+	+	+	+	+	+	+	+
Venting and Flaring	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Total	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.5**	**1.6**

+ Does not exceed 0.05 MMTCE
Note: Totals may not sum due to independent rounding.

Table 2-28: CH_4 Emissions from Petroleum Systems (Gg)

Stage	1990	1991	1992	1993	1994	1995	1996	1997
Production Field Operations	24	25	24	24	24	23	23	23
Crude Oil Storage	2	2	2	2	2	2	2	2
Refining	10	10	10	10	10	10	9	9
Tanker Operations	6	6	5	5	5	5	5	5
Venting and Flaring	231	231	231	231	231	231	231	231
Total	**272**	**273**	**272**	**272**	**272**	**271**	**271**	**271**

Note: Totals may not sum due to independent rounding.

Refining. Tilkicioglu and Winters (1989) also estimated methane emissions from waste gas streams based on measurements at ten refineries. These data were extrapolated to total U.S. refinery capacity to estimate emissions from refinery waste gas streams for 1990. To estimate emissions for 1991 through 1997, the emissions estimates for 1990 were scaled using updated data on U.S. refinery capacity.

Tanker Operations. Methane emissions from tanker operations are associated with the loading and unloading of domestically-produced crude oil transported by tanker, and the unloading of foreign-produced crude transported by tanker. The quantity of domestic crude transported by tanker was estimated as Alaskan crude oil production less Alaskan refinery crude utilization, plus 10 percent of non-Alaskan crude oil production. Crude oil imports by tanker were estimated as total imports less imports from Canada. An emission factor based on the methane content of hydrocarbon vapors emitted from crude oil was employed (Tilkicioglu and Winters 1989). This emission factor was multiplied by updated activity data to estimate total emissions for 1990 through 1997.

Venting and Flaring. Although venting and flaring data indicate that the amount of venting and flaring activity has changed over time, there is currently insufficient data to assess the change in methane emissions associated with these fluctuations. Given the considerable uncertainty in the emissions estimate for this stage, and the inability to discern a trend in actual emissions, the 1990 emissions estimate was held constant for the years 1991 through 1997.

See Annex F for more detailed information on the methodology and data used to calculate methane emissions from petroleum systems.

Data Sources

Data on the number of oil wells in production fields were taken from the American Petroleum Institute (API 1998) as was the number of oil wells that do not produce natural gas. Crude oil storage, crude oil stocks, crude oil production, utilization, and import data were obtained from the U.S. Department of Energy (EIA 1991, 1992, 1993, 1994, 1995, 1996, 1997, 1998). U.S. refinery capacity and Alaskan refinery crude capacity data were extrapolated based on estimates for 1990 through 1996 (EIA 1990, 1991, 1992, 1993, 1994, 1995, 1997). Emission factors were taken from Tilkicioglu and Winters (1989) and EPA (1993).

Uncertainty

There are significant uncertainties associated with all aspects of the methane emissions estimates from petroleum systems. Published statistics are inadequate for estimating activity data at the level of detail required. Similarly, emission factors for each stage remain uncertain. In particular, there is insufficient information to estimate annual venting and flaring emissions using published statistics. EPA is currently undertaking more detailed analyses of emissions from this source and anticipates that new information will be available for future inventories. Preliminary work suggests that emission estimates will increase. Table 2-29 provides emission estimate ranges given the uncertainty in the venting and flaring estimates.

Table 2-29: Uncertainty in CH_4 Emissions from Petroleum Systems (Gg)

Stage	1990	1991	1992	1993	1994	1995	1996	1997
Venting and Flaring (point estimate)	**231**	**231**	**231**	**231**	**231**	**231**	**231**	**231**
Low	93	93	93	93	93	93	93	93
High	462	462	462	462	462	462	462	462
Total (point estimate)	**272**	**273**	**272**	**272**	**272**	**271**	**271**	**271**
Low	103	103	103	103	103	102	102	102
High	627	631	628	627	625	621	620	621

Natural Gas Flaring and Criteria Pollutant Emissions from Oil and Gas Activities

The flaring of natural gas from oil wells is a small source of carbon dioxide (CO_2). In addition, oil and gas activities also release small amounts of nitrogen oxides (NO_x), carbon monoxide (CO), and nonmethane volatile organic compounds (NMVOCs). This source accounts for only a small proportion of overall emissions of each of these gases. Emissions of CO_2, NO_x, and CO from petroleum and natural gas production activities are all less than 1 percent of national totals, while NMVOC emissions are roughly 3 percent of national totals.

Carbon dioxide emissions from petroleum production result from natural gas that is flared (i.e., combusted) at the production site. Barns and Edmonds (1990) noted that of total reported U.S. venting and flaring, approximately 20 percent may be vented, with the remaining 80 percent flared; however, it is now believed that flaring accounts for an even greater proportion, although some venting still occurs. Methane emissions from venting are accounted for under Petroleum Systems. For 1997, the CO_2 emissions from the flaring were estimated to be approximately 4.2 MMTCE (15.2 Tg), an increase of 82 percent since 1990 (see Table 2-30).

Criteria pollutant emissions from oil and gas production, transportation, and storage, constituted a relatively small and stable portion of the total emissions of these gases for the 1990 to 1997 period (see Table 2-31).

Table 2-30: CO_2 Emissions from Natural Gas Flaring

Year	MMTCE	Tg
1990	2.3	8.4
1991	2.6	9.6
1992	2.6	9.4
1993	3.5	13.0
1994	3.6	13.1
1995	4.5	16.4
1996	4.3	15.7
1997	4.2	15.2

Table 2-31: NO_x, NMVOCs, and CO Emissions from Oil and Gas Activities (Gg)

Year	NO_x	CO	NMVOCs
1990	139	302	555
1991	110	313	581
1992	134	337	574
1993	111	337	588
1994	106	307	587
1995	100	316	582
1996	100	316	469
1997	104	330	488

Methodology

The estimates for CO_2 emissions were prepared using an emission factor of 14.92 MMTCE/QBtu of flared gas, and an assumed flaring efficiency of 100 percent. The quantity of flared gas was estimated as the total reported vented and flared gas minus a constant 12,031 million cubic feet, which was assumed to be vented.[18]

Criteria pollutant emission estimates for NO_x, CO, and NMVOCs were determined using industry-published production data and applying average emission factors.

Data Sources

Activity data in terms of total natural gas vented and flared for estimating CO_2 emissions from natural gas flaring were taken from EIA's *Natural Gas Annual* (EIA 1998). The emission and thermal conversion factors were also provided by EIA (see Table 2-32)

EPA (1998) provided emission estimates for NO_x, CO, and NMVOCs from petroleum refining, petroleum product storage and transfer, and petroleum marketing operations. Included are gasoline, crude oil and distillate fuel oil storage and transfer operations, gasoline bulk terminal and bulk plants operations, and retail gasoline service stations operations.

Uncertainty

Uncertainties in CO_2 emission estimates primarily arise from assumptions concerning what proportion of natural gas is flared and the flaring efficiency. The portion assumed vented as methane in the methodology for Petroleum Systems is currently held constant over

[18] See the methodological discussion under Petroleum Systems for the basis of the portion of natural gas assumed vented.

Table 2-32: Total Natural Gas Reported Vented and Flared (million ft^3) and Thermal Conversion Factor (Btu/ft^3)

Year	Vented and Flared	Thermal Conversion Factor
1990	150,415	1,106
1991	169,909	1,108
1992	167,519	1,110
1993	226,743	1,106
1994	228,336	1,105
1995	283,739	1,106
1996	272,117	1,106
1997	263,819	1,106

the period 1990 through 1997 due to the uncertainties involved in the estimate. Uncertainties in criteria pollutant emission estimates are partly due to the accuracy of the emission factors used and projections of growth.

International Bunker Fuels

Emissions resulting from the combustion of fuels used for international transport activities, termed international bunker fuels under the UN Framework Convention on Climate Change (UNFCCC), are currently not included in national emission totals, but are reported separately on the basis of fuel sold in each country. The decision to report emissions from international bunker fuels separately, instead of allocating them to a particular country, was made by the Intergovernmental Negotiating Committee in establishing the Framework Convention on Climate Change.[19] These decisions are reflected in the *Revised 1996 IPCC Guidelines*, in which countries are requested to report emissions from ships or aircraft that depart from their ports and are engaged in international transport separately from national totals (IPCC/UNEP/OECD/IEA 1997). The Parties to the UNFCCC have yet to decide on a methodology for allocating these emissions.[20]

Greenhouse gases emitted from the combustion of international bunker fuels, like other fossil fuels, include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), carbon monoxide (CO), oxides of nitrogen (NO_x), nonmethane volatile organic compounds (NMVOCs), particulate matter, and sulfur dioxide (SO_2).[21] Two transport modes are addressed under the IPCC definition of international bunker fuels: aviation and marine. Emissions from ground transport activities—by road vehicles and trains—even when crossing international borders are allocated to the country where the fuel was loaded into the vehicle and, therefore, are not counted as bunker fuel emissions.

The IPCC Guidelines distinguish between different modes of air traffic. Civil aviation comprises aircraft used for the commercial transport of passengers and freight, military aviation comprises aircraft under the control of national armed forces, and general aviation applies to recreational and small corporate aircraft. The IPCC Guidelines further define international bunker fuel use as the fuel combusted for civil (commercial) aviation purposes by aircraft arriving or departing on international flight segments. However, as mentioned above, only the fuel used by aircraft taking-off (i.e., departing) from the United States are reported here. The standard fuel used for civil aviation is kerosene-type jet fuel, while the typical fuel used for general aviation is aviation gasoline.[22]

Emissions of CO_2 from aircraft are a function of fuel use, whereas emissions per flight or ton-mile in the case of cargo, are a function of flight path, fuel efficiency of the aircraft and its engines, occupancy, and load factor. Methane, N_2O, CO, NO_x, and NMVOC emissions depend upon engine characteristics, flight conditions, and flight phase (i.e., take-off, climb, cruise, decent, and landing). Methane, CO, and NMVOCs are the product of incomplete combustion and occur mainly during the landing and take-off phases. In jet engines, N_2O and NO_x are primarily produced by the oxidation

[19] See report of the Intergovernmental Negotiating Committee for a Framework Convention on Climate Change on the work of its ninth session, held at Geneva from 7 to 18 February 1994 (A/AC.237/55, annex I, para. 1c) (contact secretariat@unfccc.de).

[20] See FCCC/SBSTA/1996/9/Add.1 and Add.2 for a discussions of allocation options for international bunker fuels (see http://www.unfccc.de/fccc/docs/1996/sbsta/09a01.pdf and /09a02.pdf).

[21] Sulfur dioxide emissions from jet aircraft and marine vessels, although not estimated here, are mainly determined by the sulfur content of the fuel. On average jet fuel has a sulfur content around 0.05 percent, while distillate diesel fuel averages around 0.3 percent and residual fuel oil around 2.3 percent.

[22] Naphtha-type jet fuel is used primarily by the military in turbojet and turboprop aircraft engines.

of atmospheric nitrogen, and the majority of emissions occur during the cruise phase. The impact of NO_x on atmospheric chemistry depends on the altitude of the actual emission. The cruising altitude of supersonic aircraft, near or in the ozone layer, is higher than that of subsonic aircraft. At this higher altitude, NO_x emissions contribute to ozone depletion.[23] At the cruising altitudes of subsonic aircraft, however, NO_x emissions contribute to the formation of ozone. At these lower altitudes, the positive radiative forcing effect of ozone is most potent.[24] The vast majority of aircraft NO_x emissions occur at these lower cruising altitudes of commercial subsonic aircraft[25] (NASA 1996).

International marine bunkers comprise emissions from fuels burned by ocean-going ships of all flags that are engaged in international transport. Ocean-going ships are generally classified as cargo and passenger carrying, military (i.e., navy), fishing, and miscellaneous support ships (e.g., tugboats). For the purpose of estimating greenhouse gas emissions, international bunker fuels are solely related to cargo and passenger carrying vessels, which is the largest of the four categories. Two main types of fuels are used on sea-going vessels: distillate diesel fuel and residual fuel oil. Carbon dioxide is the primary greenhouse gas emitted from marine shipping. In comparison to aviation, the atmospheric impacts of NO_x from shipping are relatively minor, as the emissions occur at ground level.

Overall, aggregate greenhouse gas emissions in 1997 from the combustion of international bunker fuels from both aviation and marine activities decreased by 2 percent since 1990, to 26.8 MMTCE (see Table 2-33). Although emissions from international flights departing from the United States have increased significantly (33 percent), emissions from international shipping voyages departing the United States appear to have decreased by a greater absolute amount.[26] The majority of these emissions were in the form of carbon dioxide; however, small amounts of CH_4 and N_2O were also emitted. Of the criteria pollutants, emissions of NO_x by aircraft at cruising altitudes are of primary concern because of their effects on ozone formation (see Table 2-38).

Emissions from both aviation and marine international transport activities are expected to grow in the future as both air traffic and trade increase, although emission rates should decrease over time due to technological changes.[27]

Methodology

Emissions of CO_2 were estimated through the application of carbon content and fraction oxidized factors to fuel consumption activity data. This approach is analogous to that described under CO_2 from Fossil Fuel Combustion. A complete description of the methodology and a listing of the various factors employed can be found in Annex A.

Emission estimates for CH_4, N_2O, CO, NO_x, and NMVOCs were calculated by multiplying emission factors by measures of fuel consumption by fuel type and mode. Activity data for aviation included solely jet fuel consumption statistics, while the marine mode included both distillate diesel and residual fuel oil.

Data Sources

Carbon content and fraction oxidized factors for kerosene-type jet fuel, distillate fuel oil, and residual fuel oil were taken directly from the Energy Information Administration (EIA) of the U.S. Department of Energy and are presented in Annex A. Heat content and density conversions were taken from EIA (1998). Emission factors used in the calculations of CH_4, N_2O, CO, NO_x, and NMVOC emissions were taken from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997). For aircraft emis-

[23] In 1996, there were only around a dozen civilian supersonic aircraft in service around the world which flew at these altitudes, however.

[24] However, at this lower altitude, ozone does little to shield the earth from ultraviolet radiation.

[25] Cruise altitudes for civilian subsonic aircraft generally range from 8.2 to 12.5 km (27,000 to 41,000 feet).

[26] See Uncertainty section for a discussion of data quality issues.

[27] Most emission related international aviation and marine regulations are under the rubric of the International Civil Aviation Organization (ICAO) or the International Maritime Organization (IMO), which develop international codes, recommendations, and conventions, such as the International Convention of the Prevention of Pollution from Ships (MARPOL).

Table 2-33: Emissions from International Bunker Fuels (MMTCE)

Gas/Mode	1990	1991	1992	1993	1994	1995	1996	1997
CO_2	**27.1**	**27.8**	**29.0**	**29.9**	**27.4**	**25.4**	**25.4**	**26.6**
Aviation	10.5	10.5	11.0	11.2	11.6	12.4	12.8	13.9
Marine	16.6	17.3	18.0	18.7	15.8	13.0	12.6	12.7
CH_4	**+**	**+**	**+**	**+**	**+**	**+**	**+**	**+**
Aviation	+	+	+	+	+	+	+	+
Marine	+	+	+	+	+	+	+	+
N_2O	**0.2**	**0.2**	**0.2**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**
Aviation	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Marine	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**27.3**	**28.0**	**29.3**	**30.2**	**27.6**	**25.7**	**25.6**	**26.8**

+ Does not exceed 0.05 MMTCE

Note: Totals may not sum due to independent rounding. Excludes emissions from military fuel consumption. Includes aircraft cruise altitude emissions.

Table 2-34: Emissions from International Bunker Fuels (Gg)

Gas/Mode	1990	1991	1992	1993	1994	1995	1996	1997
CO_2	**99,258**	**101,925**	**106,404**	**109,605**	**100,377**	**93,296**	**92,991**	**97,542**
Aviation	38,432	38,450	40,413	41,100	42,491	45,528	46,957	50,974
Marine	60,826	63,475	65,990	68,505	57,886	47,768	46,034	46,568
CH_4	**2**	**2**	**2**	**2**	**2**	**2**	**2**	**2**
Aviation	1	1	1	1	1	1	1	1
Marine	1	1	1	1	1	0	0	0
N_2O	**3**	**3**	**3**	**3**	**3**	**3**	**3**	**3**
Aviation	1	1	1	1	1	1	1	2
Marine	1	2	2	2	1	1	1	1
CO	**99**	**100**	**105**	**108**	**104**	**103**	**104**	**111**
Aviation	63	63	66	68	70	75	77	84
Marine	35	37	39	40	34	28	27	27
NO_x	**1,777**	**1,849**	**1,923**	**1,993**	**1,716**	**1,459**	**1,417**	**1,448**
Aviation	152	152	160	162	168	180	186	202
Marine	1,625	1,697	1,764	1,831	1,547	1,278	1,231	1,246
NMVOC	**53**	**54**	**57**	**59**	**52**	**45**	**44**	**46**
Aviation	9	9	10	10	10	11	12	13
Marine	43	45	47	49	41	34	33	33

Note: Totals may not sum due to independent rounding. Excludes emissions from military fuel consumption. Includes aircraft cruise altitude emissions.

sions, the following values, in units of grams of pollutant per kilogram of fuel consumed (g/kg), were employed: 0.09 for CH_4, 0.1 for N_2O, 5.2 for CO, 12.5 for NO_x, and 0.78 for NMVOCs. For marine vessels consuming either distillate diesel or residual fuel oil the following values, in the same units, except where noted, were employed: 0.03 for CH_4, 0.08 for N_2O, 1.9 for CO, 87 for NO_x, and 0.052 g/MJ for NMVOCs.

Activity data on aircraft fuel consumption were collected from two government agencies. Jet fuel consumed by U.S. flagged air carriers for international flight segments was supplied by the Bureau of Transportation Statistics (DOT/BTS 1998). It was assumed that 50 percent of the fuel used by U.S. flagged carriers for international flights—both departing and arriving in the United States—was purchased domestically for flights departing from the United States. In other words, only one-half of the total annual fuel consumption estimate was used in the calculations. Data on jet fuel expenditures by foreign flagged carriers departing U.S. airports was taken from unpublished data collected by the Bureau of Economic Analysis (BEA) under the U.S. Department of Commerce (BEA 1998). Approximate average fuel prices paid by air carriers for aircraft on international flights were taken from DOT/BTS

(1998) and used to convert the BEA expenditure data to gallons of fuel consumed. Final jet fuel consumption estimates are presented in Table 2-39.

Activity data on distillate diesel and residual fuel oil consumption by cargo or passenger carrying marine vessels departing from U.S. ports were taken from unpublished data collected by the Foreign Trade Division of the U.S. Department of Commerce's Bureau of the Census (DOC 1998). These fuel consumption estimates are presented in Table 2-36.

Uncertainty

Emission estimates related to the consumption of international bunker fuels are subject to the same uncertainties as those from domestic aviation and marine mobile source emissions; however, additional uncertainties result from the difficulty in collecting accurate fuel consumption activity data for international transport activities separate from domestic transport activities.[28] For example, smaller aircraft on shorter routes often carry sufficient fuel to complete several flight segments without refueling in order to minimize time spent at the airport gate or take advantage of lower fuel prices at particular airports. This practice, called tankering, when done on international flights, complicates the use of fuel sales data for estimating bunker fuel emissions. Tankering is less common with the type of large, long-range aircraft that make many international flights from the United States, however. Similar practices occur in the marine shipping industry where fuel costs represent a significant portion of overall operating costs and fuel prices vary from port to port, leading to some tankering from ports with low fuel costs.

Particularly for aviation, the DOT/BTS (1998) international flight segment fuel data used for U.S. flagged carriers does not include smaller air carriers and unfortunately defines flights departing to Canada and some flights to Mexico as domestic instead of international. As for the BEA (1998) data on foreign flagged carriers, there is some uncertainty as to the average fuel price, and to the completeness of the data. It was also not possible to determine what portion of fuel purchased by foreign carriers at U.S. airports was actually used on domestic flight segments; this error, however, is believed to be small.[29]

Table 2-35: Civil Aviation Jet Fuel Consumption for International Transport (million gallons)

Nationality	1990	1991	1992	1993	1994	1995	1996	1997
U.S. Carriers	1,982	1,970	2,069	2,078	2,155	2,256	2,329	2,482
Foreign Carriers	2,062	2,075	2,185	2,252	2,326	2,549	2,629	2,900
Total	**4,043**	**4,045**	**4,254**	**4,330**	**4,482**	**4,804**	**4,958**	**5,382**

Note: Totals may not sum due to independent rounding. Excludes military fuel consumption. The density of kerosene-type jet fuel was assumed to be 3.002 kg/gallon.

Table 2-36: Marine Vessel Distillate and Residual Fuel Consumption for International Transport (million gallons)

Fuel Type	1990	1991	1992	1993	1994	1995	1996	1997
Residual Fuel Oil	4,761	4,920	5,137	5,354	4,475	3,567	3,504	3,495
Distillate Diesel Fuel & Other	521	600	598	595	561	609	510	573

Note: Excludes military fuel consumption. The density of residual fuel oil and distillate diesel fuel were assumed to be 3.575 and 3.192 kg/gallon, respectively.

[28] See uncertainty discussions under CO_2 from Fossil Fuel Combustion and Mobile Source Fossil Fuel Combustion.

[29] Although foreign flagged air carriers are prevented from providing domestic flight services in the United States, passengers may be collected from multiple airports before an aircraft actually departs on its international flight segment. Emissions from these earlier domestic flight segments should be classified as domestic, not international, according to the IPCC.

Although aggregate fuel consumption data has been used to estimate emissions from aviation, the recommended method for estimating emissions in the *Revised 1996 IPCC Guidelines* is to use data by specific aircraft type (IPCC/UNEP/OECD/IEA 1997). The IPCC also recommends that cruise altitude emissions be estimated separately using fuel consumption data, while landing and take-off (LTO) cycle data be used to estimate near-ground level emissions.[30] The EPA is developing revised estimates based on this more detailed activity data, and these estimates are to be presented in future inventories.

There is also concern as to the reliability of the existing DOC (1998) data on marine vessel fuel consumption reported at U.S. customs stations due to the significant degree of inter-annual variation. Of note is that fuel consumption data were not available for the year 1990; therefore, an average of 1989 and 1991 data was employed.

No estimates of bunker fuel emissions resulting from military aviation or marine activities have been presented here because of a lack of detailed fuel consumption data from the U.S. Department of Defense (DOD). The DOD is developing their own institutional greenhouse gas inventory, and therefore, future U.S. inventories are expected to include estimates of military bunker fuel emissions.

Wood Biomass and Ethanol Consumption

The combustion of biomass fuels—such as wood, charcoal, and wood waste—and biomass-based fuels—such as ethanol from corn and woody crops—generates carbon dioxide (CO_2). However, in the long run the carbon dioxide emitted from biomass consumption does not increase atmospheric carbon dioxide concentrations, assuming the biogenic carbon emitted is offset by the uptake of CO_2 resulting from the growth of new biomass. As a result, CO_2 emissions from biomass combustion have been estimated separately from fossil fuel-based emissions and are not included in the U.S. totals. Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or crop lands are accounted for under the Land-Use Change and Forestry sector.

In 1997, CO_2 emissions due to burning of woody biomass within the industrial and residential/commercial sectors and by electric utilities were about 57.2 MMTCE (209.8 Tg) (see Table 2-37 and Table 2-38). As the largest consumer of woody biomass, the industrial sector in 1997 was responsible for 81 percent of the CO_2 emissions in from this source. The combined residential/commercial[31] sector was the second largest emitter, making up 18 percent of total emissions from woody biomass. The commercial end-use sector and electric utilities accounted for the remainder.

Since 1990, emissions of CO_2 from biomass burning increased by a maximum of 12 percent in 1996, before falling back to a 3 percent increase in 1997. The decrease in emissions from 1996 to 1997 was due to a 26 percent decline in woody biomass consumption in the residential/commercial sector.

Biomass-derived fuel consumption in the United States consisted mainly of ethanol use in the transportation sector. Ethanol is primarily produced from corn grown in the Midwest, and was used mostly in the Midwest and South. Pure ethanol can be combusted, or it can be mixed with gasoline as a supplement or octane-enhancing agent. The most common mixture is a 90 percent gasoline, 10 percent ethanol blend known as gasohol. Ethanol and ethanol blends are often used to fuel public transport vehicles such as buses, or centrally fueled fleet vehicles. Ethanol and ethanol blends are believed to burn "cleaner" than gasoline (i.e., lower in NO_x and hydrocarbon emissions), and have been employed

[30] It should be noted that in the EPA's *Draft National Air Pollutant Emissions Trends, 1900 - 1997* (EPA 1998), U.S. aviation emission estimates for CO, NOx, and NMVOCs are based solely upon LTO cycles and consequently only capture near ground-level emissions, which are more relevant for air quality evaluations. These estimates also include both domestic and international flights. Therefore, estimates given under Mobile Source Fossil Fuel Combustion overestimate IPCC-defined domestic CO, NO_x, and NMVOC emissions by including landing and take-off (LTO) cycles by aircraft on international flights but underestimate because they do not include emissions from aircraft on domestic flight segments at cruising altitudes. EPA (1998) is also likely to include emissions from ocean-going vessels departing from U.S. ports on international voyages.

[31] For this emissions source, data are not disaggregated into residential and commercial sectors.

Table 2-37: CO_2 Emissions from Wood Consumption by End-Use Sector (MMTCE)

End-Use Sector	1990	1991	1992	1993	1994	1995	1996	1997
Electric Utility	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4
Industrial	42.4	42.3	44.5	45.4	46.6	45.4	48.0	46.4
Residential/Commercial	12.7	13.4	14.1	12.9	12.7	14.0	14.0	10.4
Total	**55.6**	**56.2**	**59.0**	**58.8**	**59.7**	**59.7**	**62.4**	**57.2**

Note: Totals may not sum due to independent rounding.

Table 2-38: CO_2 Emissions from Wood Consumption by End-Use Sector (Tg)

End-Use Sector	1990	1991	1992	1993	1994	1995	1996	1997
Electric Utility	1.7	1.7	1.7	1.6	1.6	1.4	1.6	1.5
Industrial	155.6	155.2	163.2	166.5	170.9	166.5	175.8	170.3
Residential/Commercial	46.4	49.0	51.5	47.3	46.5	51.2	51.4	38.0
Total	**203.8**	**205.9**	**216.5**	**215.4**	**219.0**	**219.1**	**228.8**	**209.8**

Note: Totals may not sum due to independent rounding.

in urban areas with poor air quality. However, because ethanol is a hydrocarbon fuel, its combustion emits CO_2.

In 1997, the United States consumed an estimated 97 trillion Btus of ethanol (1.3 billion gallons). Emissions of CO_2 in 1997 due to ethanol fuel burning were estimated to be approximately 1.8 MMTCE (6.7 Tg) (see Table 2-39). Between 1990 and 1991, emissions of CO_2 due to ethanol fuel consumption fell by 21 percent. After this decline, emissions from ethanol steadily increased through 1997, except for a sharp decline in 1996.

Ethanol production dropped sharply in the middle of 1996 because of short corn supplies and high prices. Plant output began to increase toward the end of the growing season, reaching close to normal levels at the end of the year. However, total 1996 ethanol production fell far short of the 1995 level (EIA 1997). Production in 1997 returned to normal historic levels.

Table 2-39: CO_2 Emissions from Ethanol Consumption

Year	MMTCE	Tg
1990	1.6	5.7
1991	1.2	4.5
1992	1.5	5.5
1993	1.7	6.1
1994	1.8	6.7
1995	2.0	7.2
1996	1.4	5.1
1997	1.8	6.7

Methodology

Woody biomass emissions were estimated by converting U.S. consumption data in energy units (17.2 million Btu per short ton) to megagrams (Mg) of dry matter using EIA assumptions. Once consumption data for each sector were converted to megagrams of dry matter, the carbon content of the dry fuel was estimated based on default values of 45 to 50 percent carbon in dry biomass. The amount of carbon released from combustion was estimated using 87 percent for the fraction oxidized (i.e., combustion efficiency). Ethanol consumption data in energy units were also multiplied by a carbon coefficient (18.96 mg C/Btu) to produce carbon emission estimates.

Data Sources

Woody biomass consumption data were provided by EIA (1998) (see Table 2-40). The factor for converting energy units to mass was supplied by EIA (1994). Carbon content and combustion efficiency values were taken from the *Revised 1996 IPCC Guidelines* (IPCC/UNEP/OECD/IEA 1997).

Table 2-40: Woody Biomass Consumption by Sector (Trillion Btu)

Year	Industrial	Residential/ Commercial	Electric Utility
1990	1,948	581	21
1991	1,943	613	21
1992	2,042	645	22
1993	2,084	592	20
1994	2,138	582	20
1995	2,084	641	17
1996	2,200	644	20
1997	2,132	475	19

Table 2-41: Ethanol Consumption

Year	Trillion Btu
1990	82
1991	65
1992	79
1993	88
1994	97
1995	104
1996	74

Emissions from ethanol were estimated using consumption data from EIA (1998) (see Table 2-41). The carbon coefficient used was provided by OTA (1991).

Uncertainty

The combustion efficiency factor used is believed to under estimate the efficiency of wood combustion processes in the United States. The IPCC emission factor has been used because better data are not yet available. Increasing the combustion efficiency would increase emission estimates. In addition, according to EIA (1994) commercial wood energy use is typically not reported because there are no accurate data sources to provide reliable estimates. Emission estimates from ethanol production are more certain than estimates from woody biomass consumption due to better activity data collection methods and uniform combustion techniques.